

The Second Assessment of the Effects of Climate Change on Federal Hydropower

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THE SECOND ASSESSMENT OF THE EFFECTS OF CLIMATE CHANGE ON FEDERAL HYDROPOWER

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September 2016

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ABSTRACT

Hydropower is a key contributor to the US renewable energy portfolio due to its established development history and the diverse benefits it provides to the electric power system. Ensuring the sustainable operation of existing hydropower facilities is of great importance to the US renewable energy portfolio and the reliability of electricity grid. As directed by Congress in Section 9505 of the SECURE Water Act (SWA) 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, has prepared a second quinquennial report on examining the potential 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 (ORNL) Technical Memorandum, referred to as the *9505 assessment*, describes the technical basis for the report to Congress that was called for in the SWA.

To evaluate the potential climate change effects on 132 federal hydropower plants across the entire US, a spatially consistent assessment approach is designed to enable an interregional comparison. This assessment uses a series of models and methods with different spatial resolutions to gradually downscale the global climate change signals into watershed-scale hydrologic projections to support hydropower impact assessment. A variety of historic meteorological and hydrologic observations, hydropower facility characteristics, and geospatial datasets is collected to support model development, calibration, and verification.

Among most of the federal hydropower plants throughout the US, the most important climate change effect on hydrology is likely to be the trend toward earlier snowmelt and change of runoff seasonality. Under the projections of increasing winter/spring runoff and decreasing summer/fall runoff, water resource managers may need to consider different water use allocations. With the relatively large storage capacity in the most of the US federal hydropower reservoirs, the system is likely to be able to absorb part of the runoff variability and hence may continue to provide stable annual hydropower generation in the projected near-term and midterm future periods. Nevertheless, the findings are based on the assumption that there is no significant change in the future installed capacity and operation. The issues of aging infrastructures, competing water demand, and environmental requirements may reduce the system's ability to mitigate runoff variability and increase the difficulty of future operation. These issues are not quantitatively analyzed in this study.

This study presents a regional assessment at each of the eighteen PMA study areas. This generalized approach allows for spatial consistency throughout all study areas, enabling policymakers to evaluate potential climate change impacts across the entire federal hydropower fleet. This effort is expected to promote better understanding of the sensitivity of federal power plants to water availability and provides a basis for planning future actions that will enable adaptation to climate variability and change.

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EXECUTIVE SUMMARY

Hydropower is a key contributor to the US renewable energy portfolio due to its established development history and the diverse benefits it provides to electric power systems. Ensuring the sustainable operation of existing hydropower facilities is of great importance to the US renewable energy portfolio and the reliability of electricity grid. This study, *The Second Assessment of the Effects of Climate Change on Federal Hydropower*, directed by Section 9505 of the SECURE Water Act (SWA) of 2009, is the second quinquennial report evaluating the potential climate change impacts on hydroelectric energy generated from 132 US federal hydropower plants. The technical assessment is conducted by Oak Ridge National Laboratory (ORNL) under the guidance of Water Power Technologies Office, within Office of Energy Efficiency and Renewable Energy (EERE) of the US Department of Energy (DOE). This study is the result of extensive consultation with the federal Power Marketing Administrations (PMAs), as well as with other agencies, including federal hydropower owners (the US Army Corps of Engineers [USACE] and the Bureau of Reclamation [Reclamation]). The main findings of this assessment, along with PMA Administrators' Recommendation, will be included in a subsequent DOE Report to Congress. The assessment method and the technical findings are described in this report.

Methodology

To evaluate the large-scale climate change effects on all federal hydropower plants across the entire US, a spatially consistent assessment approach is designed to enable an interregional comparison. This approach uses a series of models and methods with different spatial resolutions to gradually downscale the global climate change signals into watershed-scale hydrologic projections to support a hydropower impact assessment (Fig. ES.1). A variety of historic meteorological and hydrologic observations, hydropower facility characteristics, and geospatial datasets is collected to support model development, calibration, and verification. Simulation outputs feature eighteen study areas from four PMAs, including 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) (Fig. ES.2).

Climate projections presented herein are based on the high-resolution refinement of the global climate models (GCMs) that are the basis of the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment (AR5). An ensemble of 10 IPCC AR5 GCMs under the representative concentration pathway (RCP) 8.5 emission scenario was selected based primarily on the availability of necessary sub-daily atmospheric data for dynamical downscaling. The Abdus Salam International Centre for Theoretical Physics Regional Climate Model version 4 (RegCM4) was used to dynamically downscale the GCM signals from over 150 kilometers (km) to an 18-km grid resolution over the entire conterminous United States (CONUS). This was done for a 1966–2005 baseline and for 2011–2050 future periods. The downscaled daily temperature and precipitation outputs were then bias-corrected and spatially disaggregated to a 4-km grid resolution for hydrologic simulation.

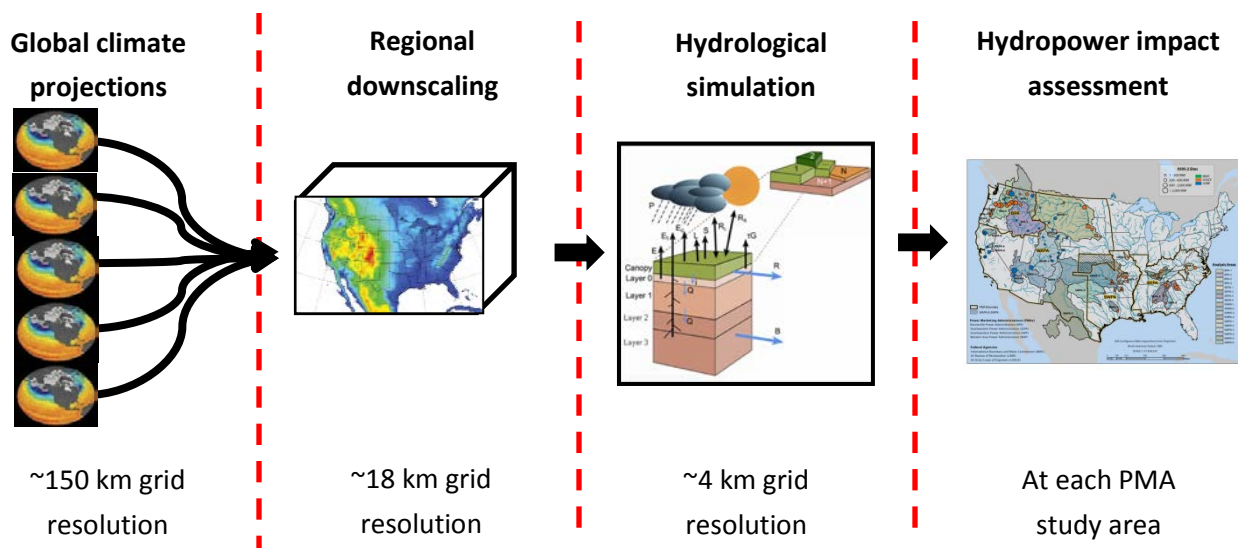


Fig. ES.1. Series of models applied in this assessment.

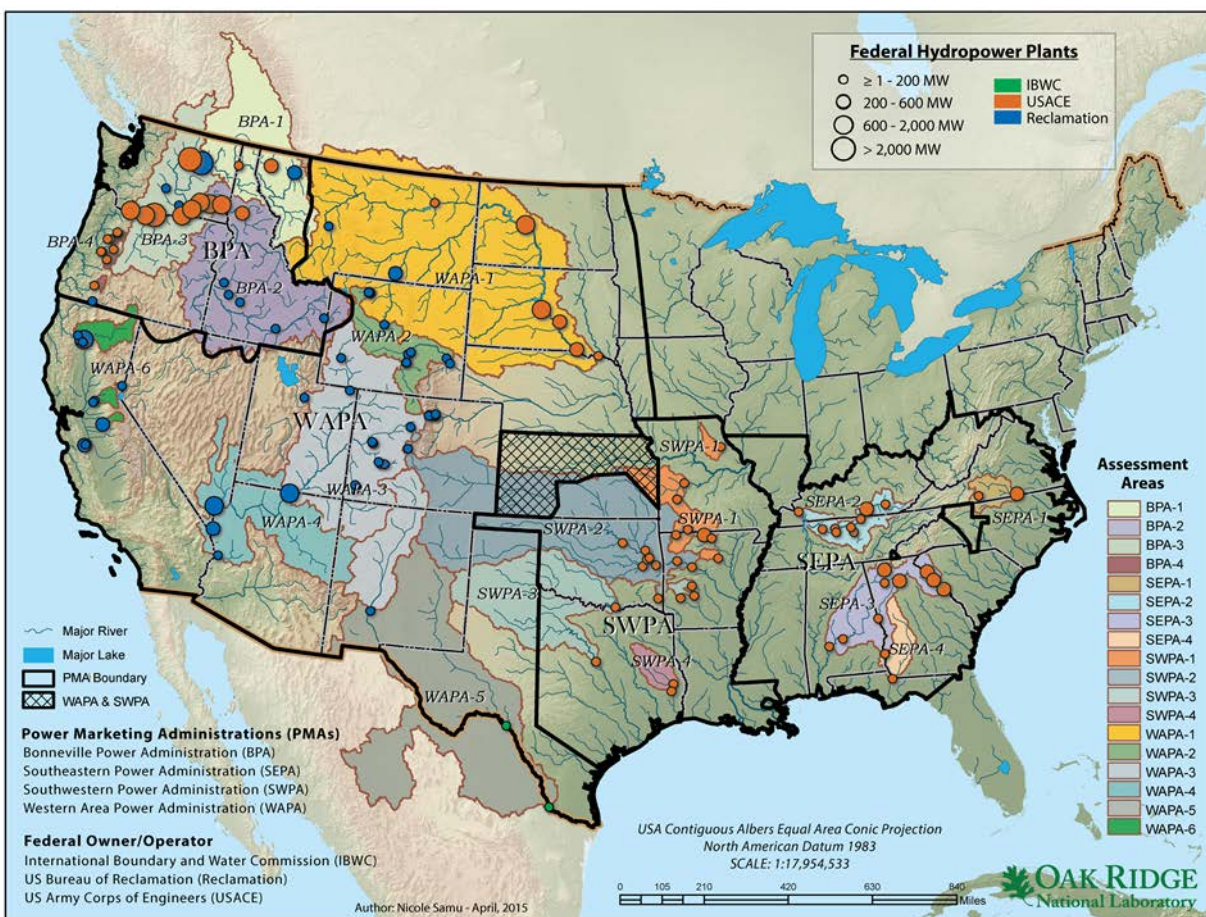


Fig. ES.2. Federal hydropower facilities built and operated by the USACE and Reclamation, plus federal power marketing regions in the US. Note that part of Kansas is supplied by both Western and Southwestern.

Accurately modeling water availability is a principal concern for this assessment, as the timing and volume of water that is available directly affects hydropower projections. To simulate the watershed response to the projected future meteorological conditions, the widely accepted Variable Infiltration Capacity (VIC) hydrologic model was used to simulate future water availability for hydropower generation. Substantial efforts were made to improve the spatial resolution, data quality, and model accuracy of hydrologic simulation through computationally intensive model calibration. The hydrologic model outputs were used to simulate future hydropower generation and climate change effects on watersheds upstream of all federal hydropower plants.

Water availability typically dominates water allocation decisions for hydropower production among a suite of other objectives (e.g., flood control, water supply, navigation, environmental protection and recreation). To capture long-term (annual and multiyear) and short-term (daily and seasonal) hydropower generation allocation decisions and to determine how generation would change given future climate conditions, a lumped Watershed Runoff-Energy Storage (WRES) model was developed. For each PMA study area, the WRES model used the monthly precipitation and unregulated runoff as inputs, performed a runoff mass balance calculation for the total monthly runoff storage in all reservoirs and retention facilities in the watershed, and simulated the monthly-regulated runoff release and hydropower generation through the system. These monthly projections provide unique seasonal and annual perspectives for when and to what extent the hydropower fleet may experience challenges in meeting the many competing demands.

Differences from the previous assessment

The previous 9505 assessment was designed to evaluate the potential changes in annual hydropower production in the near term (2010–2024) and midterm (2025–2039). The ensemble of future climate projections was created by downscaling five realizations from one IPCC Fourth Assessment (AR4) GCM under the A1B emission scenario. The regional climate and hydrologic models were both in their earlier versions and were implemented at a coarser spatial resolution. Given the methodological limitations in the first 9505 assessment, seasonal hydropower generation was not quantitatively studied. This second 9505 assessment built upon the framework established in the previous assessment and improved upon the data collection and modeling of future potential climate change effects on federal hydropower generation by including state-of-the-art scientific information and modeling techniques.

The previous 9505 assessment identified a strong linear relationship between annual regional runoff and historic generation, and the second 9505 assessment found that the projected seasonal variations in runoff would translate into variations in seasonal hydropower generation. The magnitude of the variation, however, may be nonlinear, depending upon regional storage capabilities. The previous 9505 assessment also showed that the projected effects of climate change on annual hydropower generation were not significant. Annual hydropower projections in this 9505 assessment show some PMA regions with significant-to-negligible changes, which can be further explained by watershed storage. Watershed storage may provide a buffer to help absorb part of the runoff variability, resulting in a stable future annual hydropower projection that supports the result in the first study, which used different modeling methods.

Results

The main findings of this study include:

- Air temperature is projected to increase in all areas and in all seasons by about +2 °F in the near term and +3.5 °F in the midterm future periods.
- In terms of the multimodel median, precipitation is projected to slightly increase. A large multimodel uncertainty and regional variability of precipitation projections is also identified. Overall, more precipitation is projected in the midterm than near-term future periods. Higher increase of precipitation is projected in the Southwestern and Southeastern regions, as well as in WAPA-1 in the Upper Missouri River Basin.
- The projection of future runoff varies significantly by regions. In the snowmelt-dominated regions (such as most of the Bonneville and Western regions), the winter and spring runoff is projected to increase, while the summer and fall runoff is projected to decrease. Such shift of runoff seasonality is likely caused by the increasing air temperature and earlier snowmelt. In the rainfall-dominated regions (Southwestern, Southeastern, and some areas of Bonneville and Western), the change of runoff is mainly controlled by the change of precipitation. In terms of the range of change, the percentage change of future runoff is larger than the percentage change of precipitation. The result is consistent with the findings from the hydrologic model sensitivity analysis in Section 2.4.4.
- The change of future hydropower generation is mainly controlled by the change of future runoff and precipitation. Since the combined reservoir storage may provide a buffer to help absorb part of the runoff variability, the projected change of future hydropower generation is found to be in a smaller magnitude than the projected change of future runoff (for example, WAPA-4 that covers Hoover Dam and Lake Mead). The impact of the reduction of runoff variability on hydropower generation is less noticeable in regions with relatively larger reservoir storage capacities (such as Bonneville and Western). For regions with smaller storage capacities (such as Southwestern and Southeastern), the change of future hydropower generation will follow the change of future runoff more closely.

The total annual hydropower generation marketed by each PMA and also by all PMAs as a group is further summarized in Fig. ES.3. To show the multimodel variability, each horizontal bar in Fig. ES.3 consists of 10 smaller bars for each downscaled climate model, sorted descendingly from top to bottom. For comparison, the multimodel baseline (1966–2005) average is marked with a bold vertical line. In terms of the annual generation from all PMA regions (i.e., 132 federal hydropower plants that are marketed through the four PMAs), the projected hydropower generation in the near-term future period is diverse, with half of the models suggesting increasing generation and the other half suggesting decreasing generation. More hydropower generation is projected in the midterm future period, with eight out of ten models showing an increasing hydropower trend. Among all PMAs, the average near-term Bonneville hydropower generation is projected to decrease. The change in the near-term Western and Southeastern regions is diverse, with the multimodel median close to the baseline reference. In other regions and time periods, the annual hydropower generation is generally projected to increase. Such results are consistent with the projected change of total annual runoff in each PMA study area.

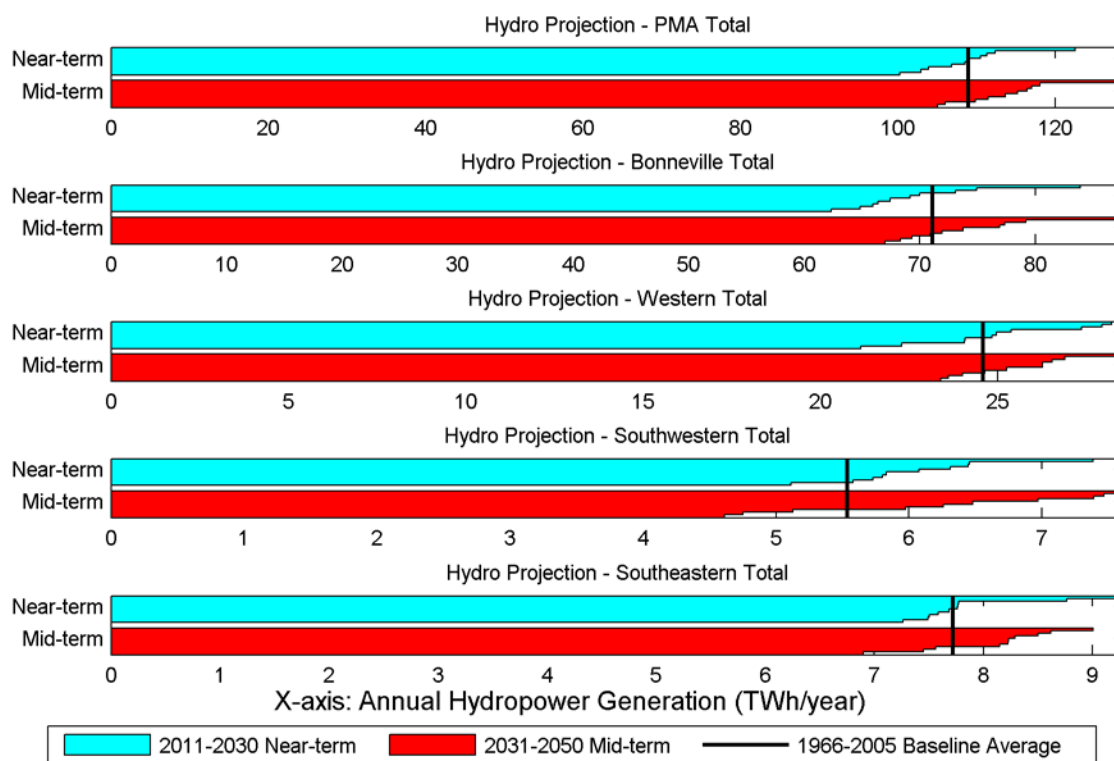


Fig. ES.3. Summary of annual hydropower projection in the near-term (2011–2030) and midterm (2031–2050) future periods for each PMA. Each horizontal bar consists of 10 smaller bars for each downscaled climate model (sorted descendingly from top to bottom). The multimodel baseline (1966–2005) average is marked with a bold black vertical line for comparison.

The seasonal hydropower projections are summarized in Fig. ES.4. In terms of the total seasonal generation from all PMA regions, the majority of models project increasing generation in winter and spring, and decreasing generation in summer and fall. Such a result is mainly governed by the projected change in the Bonneville region, which in turn is caused by the earlier snowmelt and changing runoff seasonality. A similar effect of earlier snowmelt on generation can also be observed in some Western study areas, but it cannot be clearly seen in the Western total given the diverse portfolio of hydropower plants across a wide range of geographical locations. Increasing seasonal generation is projected for both Southwestern and Southeastern, which is heavily controlled by the seasonal variability of precipitation and runoff. When compared to Bonneville and Western, the hydropower reservoirs in the Southwestern and Southeastern regions have less storage capacity, so the projected change of seasonal hydropower generation will follow the projected change of seasonal runoff more closely.

Assessment limitations

To achieve a comprehensive evaluation of possible climate change effects across a large number of hydropower plants along distinct river systems, this study focused on regional assessment at each PMA study area rather than at individual reservoirs or power plants. Regionally lumped models or generalized indices were used to evaluate the likelihood of change in future water availability, high- and low-runoff events, hydropower generation, environmental flow constraints, and power marketing dynamics within each PMA study area. The site-specific features such as

reservoir operation rules, water withdrawal/return, competing water and energy demand, and environmental minimum flow requirements were not explicitly modeled at each power plant. The assessment also did not attempt to project climate change effects on hydropower beyond 2050 because there are many other non-climate issues that will interact with potential climate effects and that are dependent on policy decisions of several types. The proposed assessment method does not replace the existing site-specific models and tools now used by water and energy resource managers. This study provides a first-order assessment to identify areas with the highest risk under projected climate conditions.

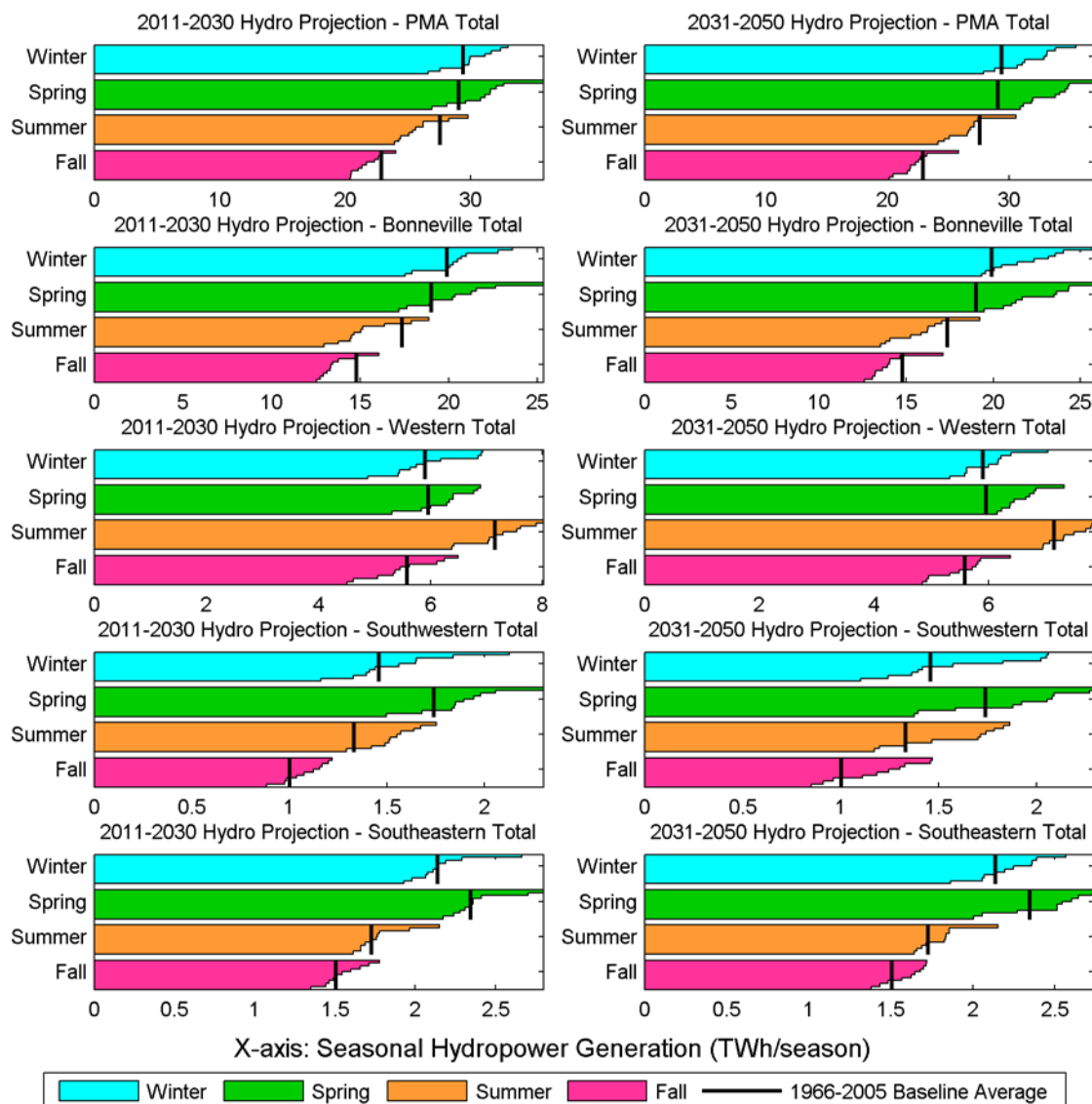


Fig. ES.4. Summary of seasonal hydropower projection in the near-term (2011–2030) and midterm (2031–2050) future periods for each PMA. Each horizontal bar consists of 10 smaller bars for each downscaled climate model (sorted descendingly from top to bottom). The multimodel baseline (1966–2005) average is marked with a bold black line for comparison.

Conclusion

The second 9505 assessment addresses how climate change may affect future US federal hydropower generation, using enhanced modeling methods at finer timescales to further inform policymakers. A spatially consistent assessment approach was designed to evaluate hydropower generation from 132 federal hydropower plants that are marketed by 4 PMAs. A variety of historic meteorological and hydrologic observations, hydropower facility characteristics, and geospatial datasets were collected to support the model development, calibration, and verification. The results present a discussion of the potential regional effects and risks of climate change with regard to this hydropower fleet at the annual and seasonal level in the near-term (2011–2030) and midterm (2031–2050) future periods.

Management of the US hydropower fleet in the face of uncertain and changing climate conditions will benefit from long-term projections, showing a range of extreme events at the sub-regional level, that carefully consider local hydrological conditions and power marketing practices. The most important climate change effects on hydropower generation are likely to be early snowmelt and change of runoff seasonality. Since future hydropower generation will be largely controlled by changes in runoff and precipitation conditions, reservoir storage provides a vital buffer to help absorb runoff variability. For regions with smaller storage capacities, the change in future hydropower generation will more closely follow the projected change in runoff. With the relatively large storage capacities at many US federal hydropower reservoirs, the fleet is likely to be able to absorb part of the runoff variability and hence may continue to provide stable annual hydropower generation in the projected near-term and midterm future periods. However, such findings are based on the assumption that there will be no significant change in the future installed capacity and operation. The issues of aging infrastructure, competing water uses, and environmental services that are themselves likely to be under greater future stresses may reduce the US hydropower fleet's ability to mitigate runoff variability and may also increase the difficulty of future operations. Resource managers should consider the risk of changing runoff conditions during water resource planning, and they may also consider conducting more in-depth, site-specific studies that explore how adjusting current operating rules may help reduce the impact of climate variability in the future.

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ABBREVIATIONS, ACRONYMS, AND INITIALISMS

ACCESS1-0	The Australian Community Climate and Earth System Simulator Model version 1.0
ACF	Apalachicola-Chattahoochee-Flint
ACT	Alabama-Coosa-Tallapoosa
AR5	IPCC's 5th Assessment Report
BCC-CSM	The Beijing Climate Center Climate System Model
BCSD	bias-correction spatial disaggregation
BPA	Bonneville Power Administration, Bonneville
CBCCSP	Columbia Basin Climate Change Scenarios Project
CCSM4	Community Climate System Model version 4
CCVA	climate change vulnerability assessment
CHWM	contract high water mark
CMCC-CM	The Centro Euro-Mediterraneo sui Cambiamenti Climatici Climate Model
CMIP5	Coupled Model Intercomparison Project
CONUS	conterminous US
CONUS-SOIL	CONUS soil dataset
CPU	central processing unit
CRCM	Canadian Regional Climate Model
DJF	Winter, December-January-February
DOE	US Department of Energy
DSI	direct service industrial
EBHOM	Energy-Based Hydropower Optimization Model
EERE	Office of Energy Efficiency and Renewable Energy
EIA	Energy Information Administration

EIM	energy imbalance market
EPA	Environmental Protection Agency
ESA	Endangered Species Act
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FY	fiscal year
GAO	Government Accountability Office
GCM	global climate model
GFDL-ESM2M	Geophysical Fluid Dynamics Laboratory-Earth System Model version 2M
GHG	greenhouse gas
GPU	graphics processing unit
GW	gigawatts
HDF	hierarchical data format
HEC-ResSim	Hydrologic Engineering Center Reservoir System Simulation
HUC2	2-digit hydrologic unit
HUC8	8-digit hydrologic unit
HYDAT	Environment Canada's water information database
IBWC	International Boundary and Water Commission
IOU	investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
IPSL-CM5A-LR	The Institute Pierre Simon Laplace Climate Model 5 running on low resolution grid
JJA	Summer, June-July-August
LAI	Leaf Area Index
LAP	Reclamation Loveland Area Project

MAE	mean absolute error
MAM	spring, March-April-May
MIROC5	The Model for Interdisciplinary Research on Climate version 5
MISO	Midwest Independent System Operator
MM5	Fifth-Generation Penn State/NCAR Mesoscale Model
MOA	Memorandum of Agreement
MODIS	Moderate Resolution Imaging Spectroradiometer
MPI-ESM-MR	The Max-Planck-Institute Earth System Model running on medium resolution grid
MRI-CGCM3	The Meteorological Research Institute Coupled ocean-atmosphere General Circulation Model version 3
NASA	National Aeronautics and Space Administration
NARCCAP	North American Regional Climate Change Assessment Program
NARR	North American Regional Reanalysis
NCEP	National Centers for Environmental Prediction
NED	National Elevation Dataset
NERC	North American Electric Reliability Corporation
NHAAP	National Hydropower Asset Assessment Program
NID	National Inventory of Dams
NorESM1-M	The Norwegian Earth System Model
NRC	National Research Council
NRCS	Natural Resources Conservation Service
NS	Nash-Sutcliffe
NWIS	National Water Information System
NWPP	Northwest Power Pool
O&M	Operations and Maintenance

ORNL	Oak Ridge National Laboratory
PMA	Power Marketing Administration
PNW	Pacific Northwest
PPA	power purchasing agreement
PPC	Public Power Council
PRISM	Parameter-elevation Regressions on Independent Slopes Model
R^2	coefficient of determination
RBM	river basin model
RCM	regional climate model
RCP	representative concentration pathway
Reclamation	Bureau of Reclamation
RECS	Residential Energy Consumption Survey
RegCM4	The Abdus Salam International Centre for Theoretical Physics Regional Climate Model version 4
RMJOC	River Management Joint Operations Committee
RMSD	root-mean-squared difference
RMSE	root mean square error
ROV	ratio of variance
RTO	regional transmission organization
SEPA	Southeastern Power Administration, Southeastern
SNOTEL	Snow Telemetry
SON	fall, September-October-November
SPA	Southwestern Power Administration
SPP	Southwest Power Pool
SPRA	Southwest Power Resources Association

SRTM	Shuttle Radar Topography Mission
STATSGO	State Soil Geographic dataset
SWA	SECURE Water Act
SWE	snow water equivalent
SWPA	Southwestern Power Administration, Southwestern
TVA	Tennessee Valley Authority
USACE	US Army Corps of Engineers
USDA	US Department of Agriculture
USGS	US Geological Survey
VIC	Variable Infiltration Capacity
WACM	Western Area Power Administration Colorado Missouri
WALC	Western Area Power Administration Lower Colorado
WAPA	Western Area Power Administration, Western
WAUE	Western Area Power Administration Upper Great Plains East
WAUW	Western Area Power Administration Upper Great Plains West
WRES	The Watershed Runoff-energy Storage model

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LIST OF VARIABLES

$b_{0,m}, b_{1,m}, \dots, b_{5,m}$	regression coefficients developed separately for each calendar month m in the WRES model
b_{infiltr}	variable infiltration curve parameter in the VIC model
D_s	fraction of the maximum velocity of base flow at which nonlinear base flow begins in the VIC model
exp	exponent of the Brooks–Corey drainage equation used in the VIC model
G	hydropower generation
G_0	initial estimate of hydropower generation in the WRES model
G_{obs}	observed hydropower generation
G_{sim}	simulated hydropower generation
GW	gigawatt (10^9 watt)
GWh	gigawatt hour (10^9 watt * hour)
kW	kilowatt (10^3 watts)
kWh	kilowatt hour (10^3 watt * hour)
mi^2	square mile
MW	megawatt (10^6 watts)
MWh	megawatt hour (10^6 watt * hour)
P	precipitation
ρ	correlation coefficient
Q	total runoff
Q_{in}	natural runoff
Q_{max}	maximum runoff-hydropower capacity
Q_{out}	regulated runoff
$S_{\text{max},m}$	maximum watershed storage in the WRES model
$S_{\text{min},m}$	minimum watershed storage in the WRES model
T	temperature
thick_2	thickness of soil layer 2 in the VIC model

thick ₃	thickness of soil layer 3 in the VIC model
TWh	terawatt hour (10^{12} watt * hour)
W/m ²	Watts per square meter
Ws	fraction of maximum soil moisture at which nonlinear base flow occurs used in the VIC model

1 INTRODUCTION

This study, “The Second Assessment of the Effects of Climate Change on Federal Hydropower,” directed by Section 9505 of the SECURE Water Act (SWA) of 2009, is the second quinquennial report on evaluating the potential climate change impacts on hydroelectric energy generated from 132 US federal hydropower plants. The technical assessment is conducted by the Oak Ridge National Laboratory (ORNL) under the guidance of Water Power Technologies Office, within Office of Energy Efficiency and Renewable Energy (EERE) of the US Department of Energy (DOE). This study is the result of extensive consultation with the federal Power Marketing Administrations (PMAs), as well as other agencies, including federal hydropower owners (the US Army Corps of Engineers [USACE] and the Bureau of Reclamation [Reclamation]). The main findings of this assessment, along with PMA Administrators’ Recommendation, will be included in a subsequent DOE report to Congress. The assessment method and the technical findings are described in this report.

1.1 Background

The Omnibus Public Land Management Act of 2009 (Public Law 111-11) Subtitle F – SECURE Water (also known as the SECURE Water Act [SWA]) was passed into law on March 30, 2009. SWA authorizes federal agencies to study and improve water management and to increase the acquisition and analysis of data describing water resources used for irrigation, hydropower, municipal uses, environmental conservation, and other purposes. A primary purpose of SWA was to facilitate an analysis and plan for potential effects that climate change may have on the hydrologic cycle that provides water for communities, economic growth, and ecosystem protection in the US. There are ten sections of the SWA legislation:

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

SWA Section 9505(c) 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). DOE is also requested to repeat these assessments every 5 years until 2023. The 9505 assessment has been conducted in coordination with each of the PMA administrators that sell and distribute hydroelectricity from federal projects, as well as with the USACE and Reclamation who own and operate federal hydropower 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 it 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 only in eight western river basins. Recognizing the overlap between 9503 and 9505, DOE and ORNL staff worked closely with Reclamation to ensure the use of comparable methods. Although the methods used in this study (see Section 2) vary somewhat from the 9503 assessment methods due to the differences in scope, the conclusions of the two reports are generally consistent and complement each other.

The first 9505 assessment was initiated in 2010 and completed in 2012 (Sale et al. 2012). To comprehensively evaluate all federal hydropower plants located at various geographical regions in the US, a nationally consistent assessment framework was designed and implemented to allow for interregional evaluation. Various types of hydropower-related data—including project characteristics, generation records, observed hydrology and meteorology data, watershed and land surface data—were organized into an integrated hydropower database to support this assessment. A strong linear relationship between regional runoff and historic generation was identified (Kao et al. 2015) and applied in conjunction with a series of hydroclimate models to project the annual hydropower generation at each federal hydropower study area for both near-term (2010–2024) and midterm (2025–2039) future periods. The technical findings were evaluated by reviewers from federal and state power and water resource managers, climate and hydrologic researchers, and policy analysts.

The main findings and suggestions from the first 9505 assessment (Sale et al. 2012) are described below:

- Changes in future climate and water availability are projected. The modeling results suggest that temperature is projected to increase across all study areas and all seasons, while precipitation and runoff are projected to change in some seasons and study areas. The results are generally consistent with other concurrent hydroclimate studies.
- In most of the study areas, the effects of climate change on annual hydropower generation are not statistically significant in the near-term (2010–2024) or midterm (2025–2039) future periods. The range of annual hydropower variability is likely to be similar to the historical range. Therefore, the current PMA contracting mechanisms should be sufficient to deal with projected climate variability in the near-term and midterm future periods. Given the methodological limitations in the first assessment, seasonal hydropower generation was not quantitatively studied.
- Earlier snowmelt is projected due to increasing temperatures. The earlier snowmelt will result in a statistically significant increase in winter/spring streamflow and a statistically significant decrease in summer/fall streamflow. Further modeling efforts will be required to study how the change in runoff seasonality may affect seasonal hydropower generation.
- Water management and investments in new equipment should focus on maintaining operational flexibility to preserve current hydropower generation.

- Continued monitoring of climate data and research advancements are needed to determine if and when current practices need to be changed.

This second 9505 assessment builds upon the framework established in the first assessment and improves upon the data collection and modeling of future climate change effects on federal hydropower generation by leveraging the best available scientific information. The latest global climate projections from the 5th phase of the Coupled Model Intercomparison Project (CMIP5) are dynamically downscaled by a regional climate model and used in conjunction with a series of calibrated hydrologic and hydropower models to study the meteorological, hydrological, and hydropower variables in the near-term (2011–2030) and midterm (2031–2050) future periods. The potential climate change impacts on federal power marketing are also extensively discussed in this study.

1.2 The United States Federal Hydropower System

Hydropower is a key contributor to the US renewable energy portfolio both because of its established development history and the diverse benefits it provides to electric power systems. Annually, approximately 6% of US electric energy is generated by hydropower (NHAAP 2014). In addition to direct hydropower generation (i.e., “Conventional Hydro” defined by the Energy Information Administration [EIA]), hydropower can also be designed for pumped storage that is known as one of the most efficient methods for storing excess energy generated from other power sources during off-peak hours. Hydropower facilities contribute to the electric system not only in the form of megawatt-hours generated, but they also bring the ability to provide frequency regulation, reserves, blackstart capability, and other ancillary services. Hydropower projects also provide substantial non-energy benefits, such as water supply, flood control, recreation opportunities, and environmental enhancements. These benefits affect all 50 states either directly or indirectly through the transmission grid. While the development of hydropower plants has slowed since the 1980s (Uría Martínez et al. 2015), the total generation from hydropower is still more than the combined energy from all other types of renewable energy. Therefore, ensuring the sustainable operation of existing hydropower facilities is of great importance to the nation’s renewable energy portfolio. Further information on regional hydropower variability can be founded in Uría Martínez et al. (2015), as well as the first 9505 assessment report (Sale et al. 2012).

1.2.1 Federal Hydropower Agencies

There are 101.2 gigawatts (GW) of hydropower projects operating in the US today consisting of 79.6 GW of conventional hydropower and 21.6 GW of pumped-storage hydropower (Uría Martínez et al. 2015). The total installed capacity is divided almost evenly between federal and nonfederal projects. 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). Most of the nonfederal hydropower is regulated by the Federal Energy Regulatory Commission (FERC) under the authority of the Federal Power Act. Ownership of nonfederal projects varies widely. Owners include investor-owned utilities (IOUs) such as the Pacific Gas and Electric Company, publicly owned utilities such as the Salt River Project, Snohomish Public Utility District, state agencies such as the New York Power Authority, wholesale power marketers such as Brookfield Renewable Power, industrial entities,

cities and municipalities like Farmington, New Mexico, and private nonutilities (Uría Martínez et al. 2015).

On average, the install capacity of federal hydropower plant is more than ten times larger than the nonfederal hydropower plants (Sale et al. 2012). Nevertheless, energy production from hydropower is only one of the many authorized purposes from federal dams. Other project purposes include flood control; navigation; water supply for municipalities, industries, agriculture, and recreation; and protection of environmental resources such as water quality, fish, and wildlife. Given that other nonpower purposes may have higher priority than power at specific projects, hydropower can be more or less a byproduct of water management operations at federal hydropower plants, being generated when water is available, or when water is passed through dams for delivery.

A summary of 132 federal hydropower plants evaluated in this study is shown in Fig. 1.1 and Table 1.1 (also see Appendix B for a detailed list). Based on river basin hydrology and power systems, the 132 federal hydropower plants are further grouped into 18 assessment areas, labeled BPA-1, BPA-2, etc., and SEPA-4 (Sale et al. 2012). USACE has the most projects, followed by Reclamation, and then IBWC. USACE currently operates 75 hydropower plants in 16 states, from Washington to Georgia (Fig. 1.1). In addition to those federally owned hydropower plants, there are more than 90 nonfederal hydropower plants located at USACE dams, with an additional 2,300 MW of capacity (USACE 2009) regulated by FERC. The oldest USACE hydropower facility is at Bonneville Dam on the lower Columbia River, which came online in 1938. The most recent USACE project to come online was the R. D. Willis project in Texas in 1989.

Table 1.1. Numbers and sizes of federal hydropower plants evaluated in this assessment

	Number of power plants	Total capacity (MW)
USACE	73 ^a	21,500
Reclamation	57 ^b	15,100
IBWC	2	100
Total federal^c	132	36,600

^a Does not include USACE Saint Marys Falls and St. Stephen, which are not marketed through PMAs.

^b Does not include Reclamation Pilot Butte that was decommissioned in 2009.

^c Does not include 30 TVA hydropower plants since TVA power is not marketed through PMAs.

Reclamation owns 76 federal hydropower plants, 53 of which it operates in 11 western states, with 58 hydropower plants marketed through PMAs. There are 60 non-federal hydropower plants on Reclamation dams and canals with a combined capacity of 500 MW. 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. Reclamation's primary 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 to external users. 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 operating in 1909. The largest is the Grand Coulee Dam, which has an installed capacity in excess of 6,800 MW, making it among the ten largest hydropower plants in the world. IBWC owns and operates two small hydropower projects

on the Rio Grande River. The hydropower from these two plants is marketed by the Western Area Power Administration (WAPA or Western).

Although federal hydropower projects are owned and operated by federal water development agencies (USACE, Reclamation, TVA, and IBWC), electricity produced at USACE, Reclamation, and IBWC projects is marketed and distributed by the PMAs. 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 with the intention to encourage the most widespread use of these federal assets.

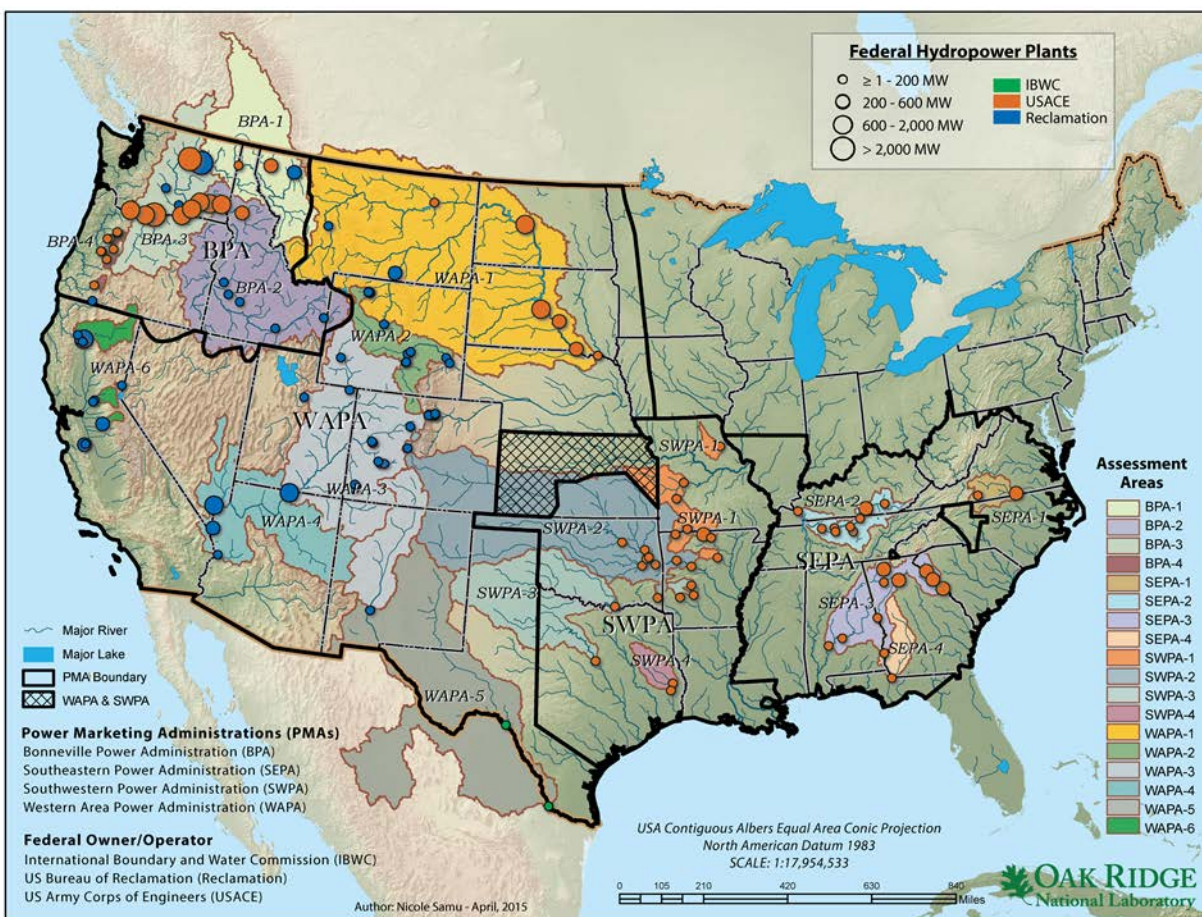


Fig. 1.1. Federal hydropower facilities and federal power marketing regions in the US. Note that part of Kansas is supplied by both Western and Southwestern.

The 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. Currently, Bonneville is the only PMA with the authority to directly finance the operations and maintenance (O&M) costs at USACE and Reclamation 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.

Based on SWA’s legislation, the scope of this report is limited to the 132 federal hydropower plants marketed through PMAs. Since TVA is not a PMA and the hydropower generated from TVA facilities is not marketed by a PMA, the 30 TVA hydropower plants are not included in this assessment. Similarly, the assessment does not include USACE Saint Marys Falls or St. Stephen projects since the electricity generated from these projects is not marketed through PMAs.

1.2.2 Marketing Federal Hydropower

Although federal hydropower projects are owned and operated by federal water development agencies (USACE, Reclamation, TVA, and IBWC), electricity produced at USACE, Reclamation, and IBWC projects is marketed and distributed by the PMAs. TVA owns, operates, and markets power from its projects, which are all located in the Tennessee River Basin. 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. The four PMAs are 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). Each PMA is a distinct, self-contained entity within DOE, much like a wholly owned subsidiary of a corporation. Bonneville is the oldest PMA and is the largest one in terms of marketed hydroelectric capacity and annual generation (Sale et al. 2012). Western is the largest PMA in terms of total area served (Fig. 1.1) and is also the newest. Both Southwestern and Southeastern are smaller, but they are also important entities in the regional energy supply.

By law, PMAs give preference to selling federal power to cooperatives and public bodies such as municipalities and irrigation districts. Such entities are generally called “preference customers.” According to the Flood Control Act of 1944, PMAs provide electricity “in such a manner as to encourage the most widespread use thereof at the lowest possible rates consistent with sound business principles.” This is a distinctive feature of PMAs relative to privately owned wholesale power marketers who operate for profit. The proceeds from the PMA power sales are used to repay the US Treasury for the initial project investment, the interest on the initial investment, any reinvestment costs plus interest, O&M costs not only for the hydropower features but also for a portion of the joint-use project costs, as well as many environmental project costs.

A PMA’s power marketing function involves managing power allocation decisions and setting the rates at which the federal hydropower is sold. The capacity and energy allocation to each preference customer is implemented through contracts between the PMA and the customer. The contracts specify the type of product to be delivered (e.g., firm power, nonfirm power, or peaking power) and terms of delivery. As for rate setting, DOE Order RA 6120.2 requires PMAs to perform annual power repayment studies. If those studies indicate that current rates are insufficient to repay the unamortized federal investment within the required period, the rates are adjusted. Rate cases are public processes, and their results must be approved by the Deputy Energy Secretary and FERC.

The details on how PMAs finance their missions vary across the four agencies. Since 1980, Bonneville is self-funded through rate recovery. Bonneville can use the power sales revenue to pay for its own annual expenses and to finance rehabilitations and upgrades at the Federal Columbia River Power System (FCRPS) hydropower plants. As a self-funded entity, Bonneville

does not depend on the process of congressional approval, authorization, and funding, which can take many years (National Research Council 2013).¹ Until, power sales revenue in the other PMAs went directly back to the US Treasury. DOE submitted a budget request to cover the PMAs' O&M expenditures, and the money appropriated for that request would flow back to the PMAs. The asset owners—USACE or Reclamation—made separate budget requests for O&M and to perform rehabilitations and upgrades on the federal hydropower plants outside of the Pacific Northwest. The Energy and Water Development and Related Agencies Appropriation Act of 2010 allowed Western, Southwestern, and Southeastern to credit revenues from the sale of power and related services, up to Congressionally approved amounts, to accounts that the three PMAs can use to pay for their annual program direction and operation and maintenance expenses. Budget requests for nonroutine O&M expenditures continue to be submitted separately by the asset owners. In addition, Western, Southwestern, and Southeastern also use customer funding agreements as a complement to appropriated funds in order to finance hydropower rehabilitations and upgrades (Uría Martínez et al. 2015).

1.3 Organization of the Report

The methods, data sources, and analyses used in this report are described in Section 2. Sections 3, 4, 5, and 6 of this report contain the PMA-specific results for Bonneville, Western, Southwestern, and Southeastern, respectively. The final section of the report, Section 7, discusses the summary and conclusions. The SWA Section 9505 calls for a Report to Congress, which 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 administrators' recommendations from each of the PMAs will be included in the subsequent report to Congress.

¹ Bonneville's access to funds for rehabilitations and upgrades is one reasons cited to explain why FCRPS performs better than most of the federal hydropower fleet.

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2 ASSESSMENT APPROACH

2.1 Scope and Objectives

To evaluate the large-scale climate change effects on all federal hydropower plants across the entire US, a spatially consistent assessment approach was designed to enable an interregional comparison. This approach uses a series of models and methods with different spatial resolutions to downscale the global climate change signals into watershed-scale hydrologic projections to support a hydropower impact assessment (Fig. 2.1). The framework is generally consistent with other hydroclimate studies (e.g., Brekke et al. 2010; Gangopadhyay and Pruitt 2011), with variations on the choice of the greenhouse gas (GHG) emission scenario, global climate models (GCMs), the downscaling approach, the hydrologic model, and/or the energy-water simulation method. A variety of historic meteorological and hydrologic observations, hydropower facility characteristics, and geospatial datasets were collected to support model development, calibration, and verification (Section 2.2). Simulation outputs feature eighteen study areas from the PMAs. Each modeling component is described in further detail in this section.

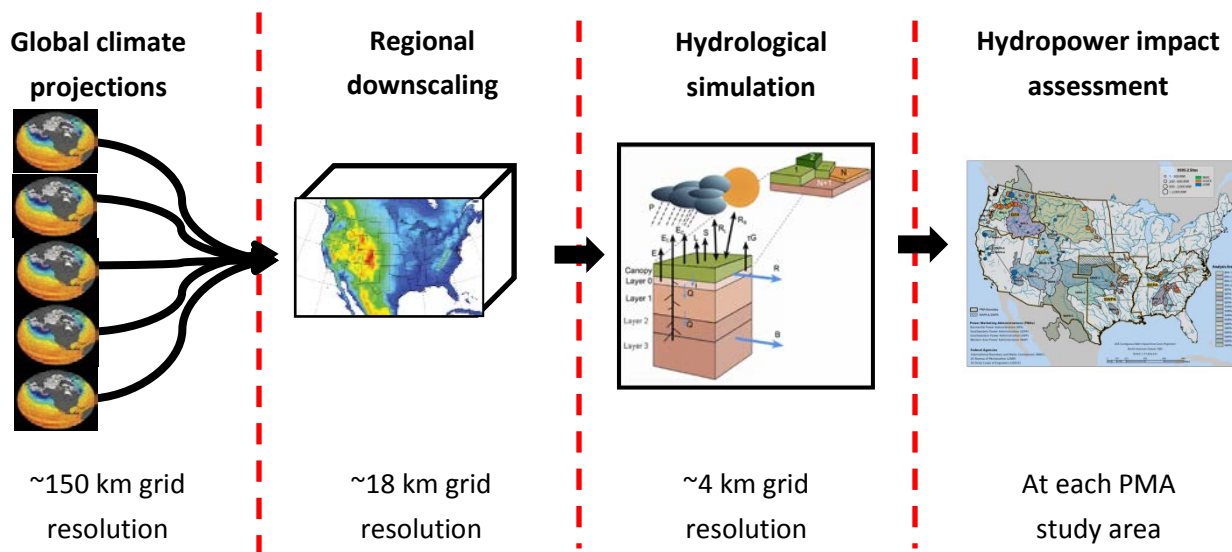


Fig. 2.1. Series of models applied in this assessment.

This study focuses on a regional assessment at each of the eighteen PMA study areas rather than at individual reservoirs or power plants. This enables comprehensive evaluation of climate change impacts across a large number of hydropower plants along distinct river systems. Regionally lumped models or generalized indices are used to evaluate the likelihood of change regarding future water availability, extreme high and low runoff events, projected hydropower generation, environmental flow constraints, and power marketing dynamics within each PMA study area. Site-specific features such as reservoir operation rules, water withdrawal/return, environmental flow requirements, and energy generation are not explicitly modeled at each power plant. This generalized approach allows for spatial consistency throughout all study areas, enabling policymakers to evaluate potential climate change impacts across the entire federal hydropower portfolio. If an issue of concern is identified for a specific region (e.g., change of streamflow seasonality), a site-specific evaluation can be planned through other future local

studies. The proposed assessment method does not replace the existing site-specific models and tools now used by water and energy resource managers. This study provides a first-order assessment to identify areas with the highest risk under projected climate conditions.

2.2 Data Sources

To support model development and verification at various stages of the assessment, a variety of data and observations were collected in this study (Table 2.1). These data include hydropower project characteristics, historic hydropower generation, observed hydrology and meteorology, and land surface information.

- **Hydropower Project Characteristics**

The US federal hydropower project characteristics were obtained from the ORNL National Hydropower Asset Assessment Program (NHAAP 2014). NHAAP is an integrated hydropower information platform maintained by ORNL for the DOE Water Power Technologies Office. Hydropower characteristics such as installed capacity, turbine types, year of operation, and dam characteristics are incorporated from multiple agencies, including EIA, FERC, USACE, Reclamation, and TVA. These US project characteristics are further reviewed and updated by PMA staff members.

- **Historical Hydropower Generation**

The historical US monthly hydropower generation data were collected from the EIA Form 906/920/923 Database (EIA 2014b), which includes data from 1970 through 2012. When available, more accurate generation records provided by Reclamation, USACE, and the PMAs are used to update parts of the survey-based EIA plant generation data. The monthly plant generation data are then aggregated for each PMA study area for further analysis.

- **Watershed Boundary and Hydrography**

The watersheds boundaries defined in the first 9505 assessment (Sale et al. 2012), based on the Watershed Boundary Dataset (US Geological Survey [USGS] and the US Department of Agriculture [USDA] Natural Resources Conservation Service [NRCS] 2009), was used again for this study. Other hydrography information (e.g., flowline and river channels) was obtained from the National Hydrography Dataset Plus (Environmental Protection Agency [EPA] and USGS 2010).

- **Observed Hydrological Data**

Two types of hydrological data, streamflow and runoff, were collected for model calibration and validation. Gauge-based streamflow observations directly measure flow discharge at a specific river channel. Comprehensive daily flow observations can be obtained from the USGS National Water Information System (NWIS) (USGS 2014) for more than 22,000 current and retired gauge stations throughout the US. For dams operated by Reclamation, additional streamflow observations can be obtained from Reclamation's Hydromet Database (Reclamation 2014). Additional streamflow observations can also be obtained from

Environment Canada's HYDAT Database (Environment Canada 2014) for gauges located in Canada's upper Columbia River Basin (part of the BPA-1 and BPA-3 study areas).

Another observational product, the USGS WaterWatch runoff (Brakebill et al. 2011), is also useful in studying regional hydropower generation (Sale et al. 2012, Kao et al. 2015). Derived from the comprehensive NWIS gauge observation, WaterWatch runoff is the assimilated time series of flow per unit of area calculated for each conterminous US (CONUS) 8-digit hydrologic unit (HUC8). For each HUC8, multiple NWIS gauge stations located within the HUC8 or downstream are used to estimate the runoff generated locally at each HUC8, with gauge weighting factors determined by joint contributing drainage areas (both gauge-to-HUC8 and HUC8-to-gauge). This approach can effectively assimilate streamflow observations from multiple gauge stations as a consistent areal HUC8 runoff measurement with a unit similar to that for precipitation (depth/time). WaterWatch runoff has been used and discussed in several recent hydroclimate studies, including Ashfaq et al. (2013), Beigi and Tsai (2014), and Oubeidillah et al. (2014). Basin runoff calculated via the WaterWatch runoff is also found to be highly correlated to the historical annual hydropower generation (Sale et al. 2012, Kao et al. 2015). For upstream watersheds in Canada, runoff is computed by a similar approach to WaterWatch using the unregulated monthly flow collected from HYDAT. The HUC8-based runoff is then weight-averaged (by their contributing areas) to form 1980–2012 monthly runoff time series for each of the 18 PMA study areas. It should be noted that both NWIS and WaterWatch could include gauges affected by river regulation, rather than naturalized streamflow where those potential effects have been accounted for. Further efforts can be performed to exclude the regulated streamflow gauges and/or incorporate naturalized streamflow information for the correction of human impairment in the WaterWatch for the purpose of more accurate hydrologic model calibration.

- **Observed Meteorological Data**

This study collected variables used for hydrologic modeling such as precipitation, temperature, and wind speed from multiple meteorological datasets.

Precipitation and temperature were obtained from multiple meteorological datasets. The Parameter-elevation Regressions on Independent Slopes Model (PRISM) (Daly et al. 2002) meteorological dataset provides gridded observation of precipitation and temperature for the entire CONUS at $1/24^\circ$ (~ 4 km) spatial resolution. Given PRISM's ability to account for topographical effects and some other orographic adjustment factors (Daly et al. 2002), it is one of the best available grid-based meteorological observations of temperature and precipitation. Another useful meteorological dataset is the ORNL Daymet (Thornton et al. 1997). Daymet is available on a daily time scale from 1980 to the present at a projected 1-km spatial resolution for the entire continent of North America. In order to use these two datasets jointly, the 1-km daily Daymet precipitation and temperature time series was aggregated and adjusted at each $1/24^\circ$ (~ 4 km) PRISM grid (degree adjustment for temperature and percentage adjustment for precipitation) so that the aggregated time series may have the same monthly values as PRISM. The hydrologic model (Section 2.4) was also established on the same PRISM grid for consistency. As with runoff averages for each PMA study area, the average 1980–2012 precipitation and temperature time series were summarized for each of

the 18 PMA study areas. These areal average monthly temperature, precipitation, and runoff data were the main variables for the subannual hydropower simulation described in Section 2.5.

For the purpose of climate model bias correction (Section 2.3), some additional temperature and precipitation data are also collected. These data are from the Pacific Northwest Hydroclimate Scenarios Project (Hamlet et al. 2013) and Maurer et al. (2002) datasets, including pre-1980 meteorological data outside the US. These periods and regions are not covered by Daymet or PRISM. For watersheds in the upper Columbia River Basin in Canada (i.e., part of the BPA-1 and BPA-3 study areas, see Fig. 1.1 or Section 3), the $1/16^\circ$ (~6 km) resolution gridded observation from Hamlet et al. (2013) is collected. For watersheds in Mexico that flow into the Rio Grande River Basin (i.e., WAPA-5 study area), the $1/8^\circ$ (~12 km) resolution Maurer et al. (2002) precipitation and temperature dataset is used. These precipitation and temperature data are interpolated to the same $1/24^\circ$ (~4 km) grid for further analysis.

Daily wind speed data from North American Regional Reanalysis (NARR) (Mesinger et al. 2006) is incorporated for the calculation of evapotranspiration during hydrologic modeling (Section 2.4). NARR is an assimilated meteorological re-analysis dataset providing a complete set of meteorological variables (e.g., pressure, wind) for the entire North American continent. These data are available at 3-hour time steps from 1979 to the present at a 36-km horizontal grid spacing. The daily wind speed is spatially interpolated to the $1/24^\circ$ (~4 km) PRISM grid. The processed daily precipitation, maximum and minimum temperature, and wind speed are the main meteorological inputs for the calibration and validation of hydrologic modeling (Section 2.4).

- **Other Land Surface Data for Hydrologic Model Development and Verification**

Other land surface data concerning topography, vegetation, soil characteristics, and snow observation are collected for the hydrologic model development and calibration.

Topography data are collected, including the $1/3$ arcsec-resolution (~10 m) National Elevation Dataset (NED) (Gesch et al. 2002), which is collected for the CONUS. For regions outside the US, the 3 arcsec-resolution (~90 m) Shuttle Radar Topography Mission (SRTM) elevation is used instead (Farr et al. 2007). These data are used to calculate the histogram of elevation at each hydrologic model grid cell to allow further, efficient calculation of the average elevation and elevation band information.

Vegetation data are collected to capture the seasonal pattern of surface vegetation and transpiration. The Moderate Resolution Imaging Spectroradiometer (MODIS) 15A2 Leaf Area Index (LAI) (Knyazikhin et al. 1999) is organized for hydrologic simulation and is defined as the green leaf area per unit of ground area (leaf area/ground area). The LAI is a widely used dimensionless canopy index. Depending on the type of vegetation, LAI may show significant seasonal trends. The MODIS 15A2 LAI information is available every 8 days and is stored in hierarchical data format (HDF) at approximately 1 km spatial resolution in sinusoidal projection. The 8-day LAI values are aggregated for each month and linked to the $1/24^\circ$ (~4 km) grid.

Soil characteristics are mainly used to describe the process of infiltration and baseflow generation in hydrologic modeling (Section 2.4). Given their heterogeneous nature and the lack of an effective remote sensing method, soil parameters are perhaps the most uncertain land surface parameters. In this study, the CONUS soil dataset (CONUS-SOIL) (Miller and White 1998) was used to provide the required soil information for hydrologic modeling. CONUS-SOIL is derived from the State Soil Geographic (STATSGO) dataset (Schwarz and Alexander 1995). It provides commonly used soil characteristics such as texture, bulk density, and porosity, all arranged in 11 standard layers ranging from 0 to 2.5 m depth and is specifically aimed at hydroclimate applications. The CONUS-SOIL dataset is available at 1 km spatial resolution and is provided in common geographic information system (GIS) formats (e.g., raster or polygon). The information is summarized at the $1/24^\circ$ (~ 4 km) grid for further calibration and simulation. For non-US regions not covered by CONUS-SOIL, the Nijssen et al. (2001) modeling parameters were used as a basis for further calibration.

Snow data were collected as part of the effort to evaluate the hydrologic model performance of snow simulation. The annual April 1st snow water equivalent (SWE) observation from the Snow Telemetry (SNOTEL) and Observed Snow Course Data and Products (USDA-NRCS 2014) were used for model verification (Section 2.4).

- **Power Marketing Data**

Wholesale electricity price: The wholesale prices that best reflect the market value of electricity marketed by each of the PMAs were collected from a variety of sources. For Bonneville and Western, EIA provides wholesale market price data at hubs situated in their regions. The Southwestern Power Pool website provides data on prices at the SPA hub which is representative of the value of power marketed by Southwestern. For Southeastern, since no public data on wholesale electricity market transactions are available, data from FERC Form 714 on the marginal cost of producing electricity in the Southern Company and TVA balancing authorities are used instead as a proxy for price. The price data were explored alongside monthly PMA generation data to estimate the degree of seasonal correlation.

PMA wholesale power purchases and PMA total sales: Data on the annual electricity volumes sold by PMAs and the electricity volumes purchased by PMAs in the wholesale market to complement federal generation were collected from EIA's Annual Electric Power Industry Report (Form 861). This form collects information on peak load, generation, electric purchases, sales, revenues, customer counts, and other metrics directly from the utilities.

Table 2.1. Summary of data sources

Data type	Data source	Reference / website
Hydropower project characteristics	<ul style="list-style-type: none"> • ORNL NHAAP Database • USACE NID • EIA Form 860 Database 	<ul style="list-style-type: none"> • NHAAP (2014); http://nhaap.ornl.gov/ • USACE (2013); http://nid.usace.army.mil • EIA (2014a); http://www.eia.gov/electricity/data/eia860/
Historic hydropower generation	<ul style="list-style-type: none"> • EIA Form 906/920/923 Database • DOE PMA 	<ul style="list-style-type: none"> • EIA (2014b); http://www.eia.gov/electricity/data/eia923/
Observed runoff and streamflow	<ul style="list-style-type: none"> • USGS NWIS • USGS WaterWatch Runoff • Reclamation Hydromet Database • Environment Canada HYDAT Database 	<ul style="list-style-type: none"> • USGS (2014); http://waterdata.usgs.gov/nwis • Brakebill et al. (2011); http://waterwatch.usgs.gov/ • Reclamation (2014); http://www.usbr.gov/pn/hydromet/ • Environment Canada (2014); http://www.ec.gc.ca/rhc-wsc/default.asp?lang=En&n=9018B5EC-1
Observed temperature and precipitation	<ul style="list-style-type: none"> • Oregon State University PRISM Dataset • ORNL Daymet Dataset • Pacific Northwest Hydroclimate Scenarios Project • Maurer et al. (2002) Gridded Meteorological Data 	<ul style="list-style-type: none"> • Daly et al. (2002); http://www.prism.oregonstate.edu/ • Thornton et al. (1997); http://daymet.ornl.gov/ • Hamlet et al. (2013); http://warm.atmos.washington.edu/2860/ • Maurer et al. (2002); http://www.engr.scu.edu/~emaurer/gridded_obs/index_gridded_obs.html
Observed wind (re-analysis)	<ul style="list-style-type: none"> • NCEP NARR 	<ul style="list-style-type: none"> • Mesinger et al. (2006); http://www.esrl.noaa.gov/psd/data/gridded/data.narr.html
Watershed boundary and hydrography	<ul style="list-style-type: none"> • USDA/NRCS Watershed Boundary Dataset • EPA/USGS National Hydrography Dataset Plus 	<ul style="list-style-type: none"> • USGS and USDA–NRCS (2009); http://nhd.usgs.gov/wbd.html • EPA and USGS (2010); http://www.horizon-systems.com/nhdplus/
Vegetation	<ul style="list-style-type: none"> • NASA MODIS 15A2 LAI 	<ul style="list-style-type: none"> • Knyazikhin et al. (1999); https://lpdaac.usgs.gov/products/modis_products_table/mod15a2
Soil parameters	<ul style="list-style-type: none"> • CONUS-SOIL Dataset 	<ul style="list-style-type: none"> • Miller and White (1998); http://www.soilinfo.psu.edu/index.cgi?soil_data&conus
Topography	<ul style="list-style-type: none"> • USGS NED 	<ul style="list-style-type: none"> • Gesch et al. (2002); 10 meter resolution, http://ned.usgs.gov/
Snow	<ul style="list-style-type: none"> • USDA/NRCS SNOTEL and Snow Course Data and Products 	<ul style="list-style-type: none"> • USDA–NRCS (2014); http://www.wcc.nrcs.usda.gov/snow/
Wholesale electricity price	<ul style="list-style-type: none"> • EIA Electricity Wholesale Market Data • Southwestern Power Pool Locational Imbalance Prices • FERC Form 714 (system lambda as a proxy for price) 	<ul style="list-style-type: none"> • http://www.eia.gov/electricity/wholesale/ • http://www.spp.org/LIPPricing/ • http://www.ferc.gov/docs-filing/forms/form-714/data.asp
PMA wholesale power purchases and PMA total sales	<ul style="list-style-type: none"> • EIA Form 861 (Annual Electric Power Industry Report) 	<ul style="list-style-type: none"> • http://www.eia.gov/electricity/data/eia861/

Notes: NASA = National Aeronautics and Space Administration; NCEP = National Centers for Environmental Prediction; NID = National Inventory of Dams

2.3 Climate Projections

Climate projection describes how climate system would react to changes in radiative forcing. These changes are commonly referred to as *climate scenarios*. While it is almost impossible to reliably forecast day-to-day weather beyond 2–3 weeks, predicting average climate conditions at the time scales of several decades in response to some set climate forcing is quite possible (Trenberth 1992). A *climate forcing* is an external influence such as an increase in GHG in the atmosphere that affects the Earth's energy balance. The Earth reacts to such a forcing through changes in radiation that influences land and atmosphere temperatures, which leads to variations in the atmospheric water content and global distribution of precipitation at spatial and temporal scales.

Typically, two approaches are used to make future climate projections: *statistical extrapolation* and *model-based simulation*. Based on a comprehensive set of observations (in-situ observations such as temperature, precipitation, and paleoclimatology evidence such as tree ring chronology) with sufficiently long periods of records, statistical extrapolation attempts to determine the future state of the climate system from the knowledge of its past behavior and present state. However, a statistical approach cannot explain the climate's response to rapid changes in external forcings such as anthropogenic variations in carbon dioxide and aerosols, as the statistical relationships learned from the data at hand remain unchanged in future extrapolations. For instance, statistical extrapolation is in particular not useful in the case of snow hydrology, because changes in snow cover are known to be driven more by the increases in temperature and less by the variations in precipitation (Ashfaq et al. 2013). On the other hand, model-based climate projection makes use of earth system models that physically represent the complex interactions of the various components of the climate system and their responses to variations in the climate forcing. Therefore, a model-based approach is considered more promising to predict a future climate response to changes in climate forcing.

The Intergovernmental Panel on Climate Change (IPCC) provides future climate projections on the basis of model-based climate experiments of past and future climates under different climate forcing. In the IPCC's 5th Assessment Report (AR5), model-based future climate projections are based on four representative concentration pathways (RCPs), which describe the cumulative measure of human emissions of GHG from all sources expressed in Watts per square meter (W m^{-2}). The four RCPs (RCP2.6, RCP4.5, RCP6 and RCP8.5) are named after a targeted radiative forcing in the year 2100 relative to the pre-industrial values. For instance, RCP8.5 exhibits the highest levels of forcing and global warming at the end of the twenty-first century, with a radiative forcing reaching $\sim 8.5 \text{ W m}^{-2}$ and greenhouse-gas concentrations exceeding 1,370 ppm. IPCC AR5 utilizes a large ensemble of GCMs to provide a range of possible changes in precipitation and temperature over the course of 21st century under each of the RCPs.

In this report, future climate projections are based on the high-resolution refinement of the GCMs that are the basis of the IPCC AR5 where an ensemble of high-resolution regional climate change experiments is generated through the dynamical downscaling of GCMs using a one-way nesting approach to 18 km horizontal spacing, and then to 4 km horizontal spacing through further statistical downscaling and bias-correction. With this approach, a high-resolution regional climate model (RCM) is forced at its lateral and lower boundaries every 6 hours using 3-

dimensional atmospheric and 2-dimensional surface fields from a GCM while no feedback is permitted from the RCM to the driving GCM.

2.3.1 Global System Modeling

The most widely used approach for future projections simulates the global earth system in order to understand the climate response to future increases in GHG through the use of GCMs. A GCM uses the equations of motion to describe processes in the atmosphere, ocean, land surface, and cryosphere and can simulate the time evolution of temperature, precipitation, atmospheric moisture, sea ice, and other variables describing the state of various components of climate system in time and space. GCMs can perform century-long simulations of a climate system to understand the long-term climate response to variations in internal (e.g., ocean circulations and atmospheric composition) and external climate forcing (e.g., solar irradiance, anthropogenic GHG, and aerosols).

Generally, a GCM-based climate projection includes several phases. First, a GCM is run under preindustrial climate conditions for centuries of modeling years to reach a stable land, atmosphere and ocean state. The historical GCM simulations of the 20th century are then performed using the observed external forcing, including GHG and aerosol concentration. The simulated hydrometeorological variables from a historical simulation are compared with the observations to understand the skillfulness of the GCM in the simulation of observed climate. Following the historical run, the future GCM experiments are performed under several different RCPs, as suggested by the IPCC.

While global climate modeling is scientifically the most sophisticated approach to study the climate response resulting from changes in various forcing factors, there is a large uncertainty in GCM-based future climate projections on regional scales, which partly stems from their lack of spatial details and errors in the simulation of large-scale circulations. Despite significant advancement in the climate modeling science since the first IPCC Assessment, the typical spatial resolution of a GCM in the AR5 is still greater than 150 km (i.e., each cell of the model grid is 150 km per side), which is insufficient to simulate the response of the subtle, local-scale climate processes and feedbacks that govern climate change at fine spatial and temporal scales (e.g., Easterling 1997, Diffenbaugh et al. 2005, Ashfaq et al. 2009). Lack of advancement towards higher-resolution GCMs is partly hampered by the fact that centennial-scale high-resolution GCM experiments are both scientifically and computationally demanding, requiring substantial improvements in the representation of the fine-scale processes and feedbacks, as well as numerical algorithms for parallel computational architectures. Therefore, as the magnitude and distribution of hydroclimatic extremes are sensitive to the horizontal grid spacing of the climate models (e.g., Meehl et al. 2000, Duffy et al. 2003), current generation of GCMs is not very reliable in projecting regional climate change and hydroclimatic extremes, particularly over regions of complex topography. GCM data are not suitable to be used directly for policy making towards regional-scale future water resource management.

2.3.2 Regional Downscaling

At present, such scale mismatch issues are best addressed by embedding a RCM within a GCM to enable finer resolution simulation over the region of interest. The GCM outputs are treated as

initial and boundary conditions during the RCM simulation. Because RCMs are configured over a limited area, their tuning is relatively less cumbersome compared to GCMs. Moreover, higher spatial resolution of RCMs provides better representation of physical processes and fine-scale feedbacks, especially over topographically complex and spatially heterogeneous regions. A disadvantage in the regional modeling approach is the lack of feedback between the driving GCM and the RCM, which may influence the simulated model responses within the finer domain. In addition, RCM skill heavily depends on the quality of the boundary forcing (provided by the driving GCM) in the representation of large-scale climate processes. It should also be noted that RCM simulations are also time-consuming (when comparing to other alternative statistical downscaling approaches) and scientifically challenging, requiring experienced modelers to ensure that the GCM signals can be accurately downscaled. Given the natural limitations, the number of available RCM ensemble members is generally constrained.

The Abdus Salam International Centre for Theoretical Physics Regional Climate Model, version 4 (RegCM4, Pal et al. 2007, Giorgi et al. 2012) was applied to downscale GCMs from the CMIP5 archive over the US. The RCM is chosen based on extensive evaluation of its performance in the simulation of temperature, precipitation, moisture, runoff, and Convective Available Potential Energy (CAPE) over the CONUS (Ashfaq et al. 2013 and 2010, Diffenbaugh and Ashfaq 2007 and 2010, Diffenbaugh et al. 2006 and 2011, Rauscher et al. 2008, Trapp et al. 2007, Walker and Diffenbaugh 2009). However, use of a single RCM may underestimate the projection's uncertainty that is associated with RCM's internal biases, particularly those related to the season convective processes. In the current configuration, the RegCM4 grid was centered at 39.00°N and 100.00°W and consisted of 202 points in the latitude direction and 306 points in the longitude direction (the domain is illustrated in Fig. 2.2). Grid points were separated at 18-km horizontal spacing, with 18 levels in the vertical direction. The Lambert Conformal Projection placed the grid corners at 50.17°N, 138.86°W (northwest); 50.10°N, 60.91°W (northeast); 19.58°N, 125.44°W (southwest); and 19.53°N, 74.40°W (southeast). In total, 10 GCMs from CMIP5 archives were downscaled to generate 10 sets of historical and future realizations under RCP 8.5. RCP 8.5 was chosen based on its potential to provide the upper bound for hydrological changes, which is useful for planning purposes. Trajectory of greenhouse gases concentration in RCP 8.5 substantially differs from other RCPs only after 2030. In each set, a historical period consists of 41 years. For the 20th century, the period ranges 1965 to 2005, and for the 21st century, the future period ranges from 2010 to 2050. Atmospheric (moisture, temperature, zonal and meridional winds) and lower boundary conditions (sea surface temperature) for the RegCM4 integrations were provided by the Australian Community Climate and Earth System Simulator Model version 1.0 (ACCESS1-0), the Beijing Climate Center Climate Model (BCC-CSM), the Community Climate System Model version 4 (CCSM4), the Centro Euro-Mediterraneo sui Cambiamenti Climatici Climate Model (CMCC-CM), the Geophysical Fluid Dynamics Laboratory-Earth System Model version 2m (GFDL-ESM2M), the Institute Pierre Simon Laplace Climate Model 5 running on low resolution grid (IPSL-CM5A-LR), the Model for Interdisciplinary Research on Climate version 5 (MIROC5), the Max-Planck-Institute Earth System Model running on medium resolution grid (MPI-ESM-MR), the Meteorological Research Institute Coupled ocean-atmosphere General Circulation Model version 3 (MRI-CGCM3), and the Norwegian Earth System Model (NorESM1-M). Details about the modeling institute, GCM resolution, and future forcing are provided in Table 2.2. The choice of CMIP5 GCMs was based on the availability of sub-daily three-dimensional atmospheric data for downscaling. While there are over 50 GCMs that contributed to the CMIP5, less than one-third

of them archive three-dimensional atmospheric fields at the sub-daily timescale, which is necessary for dynamic downscaling. Also, a few GCMs had more than one ensemble member data available for downscaling; however, only one ensemble simulation was used per GCM for consistency. To investigate the representativeness of the selected CMIP5 GCMs, their ensemble mean annual precipitation projections are compared with a larger set of CMIP5 GCM projections (37 in total). The percentage change in annual precipitation and the percent of GCMs with positive precipitation change are shown in Fig. 2.3. With the exception of the southwest region, the larger CMIP5 ensemble simulates a robust increase in precipitation in the future period that gradually intensifies in magnitude from the south to the north. The ensemble with select GCMs simulates a similar precipitation change except in the northwest region, where the response is generally muted in contrast to the increase in the larger CMIP5 ensemble. The differences over the northwest occur mainly because only 30 to 60% of the GCMs in the select GCMs ensemble simulate an increase in precipitation over the northwest compared to 50 to 80% of GCMs in the larger CMIP5 ensemble (Fig. 2.3).

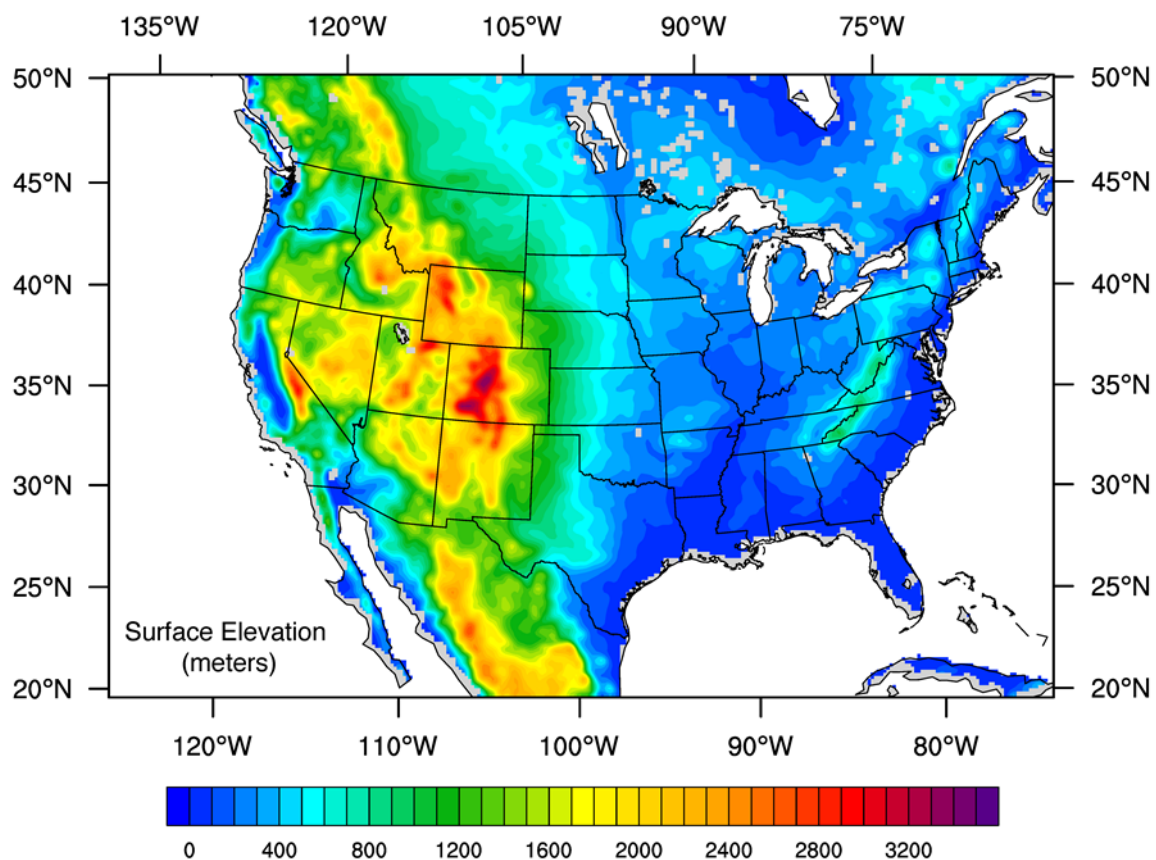


Fig. 2.2. Domain used for RCM simulation in this study.

Table 2.2. CMIP5 GCMs used for downscaling

No.	GCM name	Spatial resolution (latitude/longitude)	Emission scenario	Ensemble number	Temperature change (°C)*	Precipitation change (%)*
1	ACCESS1-0	1.24°/1.88°	RCP 8.5	r1i1p1	1.94	3.39
2	BCC-CSM1-1	2.81°/2.81°	RCP 8.5	r1i1p1	1.8	4.36
3	CCSM4	0.94°/1.25°	RCP 8.5	r6i1p1	1.7	4.52
4	CMCC-CM	0.75°/0.75°	RCP 8.5	r1i1p1	1.73	5.29
5	GFDL-ESM2M	2.00°/2.50°	RCP 8.5	r1i1p1	1.43	2.56
6	MIROC5	1.41°/1.41°	RCP 8.5	r1i1p1	1.86	6.78
7	MPI-ESM-MR	1.88°/1.88°	RCP 8.5	r1i1p1	1.85	3.3
8	MRI-CGCM3	1.13°/1.13°	RCP 8.5	r1i1p1	1.16	6.17
9	NorESM1-M	1.88°/2.50°	RCP 8.5	r1i1p1	1.73	4.13
10	IPSL-CM5A-LR	1.88°/3.75°	RCP 8.5	r1i1p1	2.04	4.99

* Average projected change calculated for the entire CONUS, 2011–2050 future to 1966–2005 baseline period.

To demonstrate improvements in the high-resolution RCM ensemble compared to the driving GCMs in terms of fine-scale variability and large-scale biases, the annual mean and extreme temperature and precipitation statistics from RCM ensemble simulations were compared with the corresponding GCM ensemble in two sets of Taylor diagrams (Taylor 2001). The first set of Taylor diagrams compared statistics at 18 km RCM grid to quantify the improvements in the representation of fine-scale variability in the RCM ensemble. The second set of Taylor diagrams compared statistics at 1° grid to quantify the reduction of large-scale biases in the RCM ensemble. The skill in each case is measured against the corresponding precipitation and temperature statistics derived from PRISM and Daymet observations. The Taylor diagram quantitatively compares the pattern correlation, the ratio of variance (ROV), and the root-mean-squared difference (RMSD). The radial coordinates represent the ROV and RMSD: ROV as a radial distance from the reference arc (labeled with a dotted arc in Fig. 2.5), and RMSD as the radial distance from the point of reference (labeled Daymet or PRISM in Fig. 2.5). Similarly, the angular coordinate represents the pattern correlation, which measures the extent to which maxima and minima in the reference data (i.e., observations) and the test data (i.e., simulated data) occur at the similar location. Because of the regional heterogeneity across the US, the results for nine climate regions were quantified as shown in Fig. 2.4. For each ensemble member, simulated mean annual precipitation, maximum temperature, minimum temperature, average temperature, extreme precipitation, extreme hot temperature, extreme cold temperature, and the wet days were compared with the corresponding PRISM observations. For the extremes statistics, precipitation extremes were calculated for the days when daily amount of precipitation extremes was at least 1 mm/day (wet days). A climatological value of 95th percentile of precipitation was used and was calculated as an average of the 95th percentile during each year of the comparison period for the calculation of the magnitude extreme precipitation. Similarly, a climatological value of 95th (5th) percentile of maximum (minimum) daily temperature was used and was calculated as an average of the 95th (5th) percentile during each year of the comparison period for the calculation of the magnitude of extreme hot (cold) temperatures.

Percent change in precipitation in 2011-2050 with respect to 1966-2005

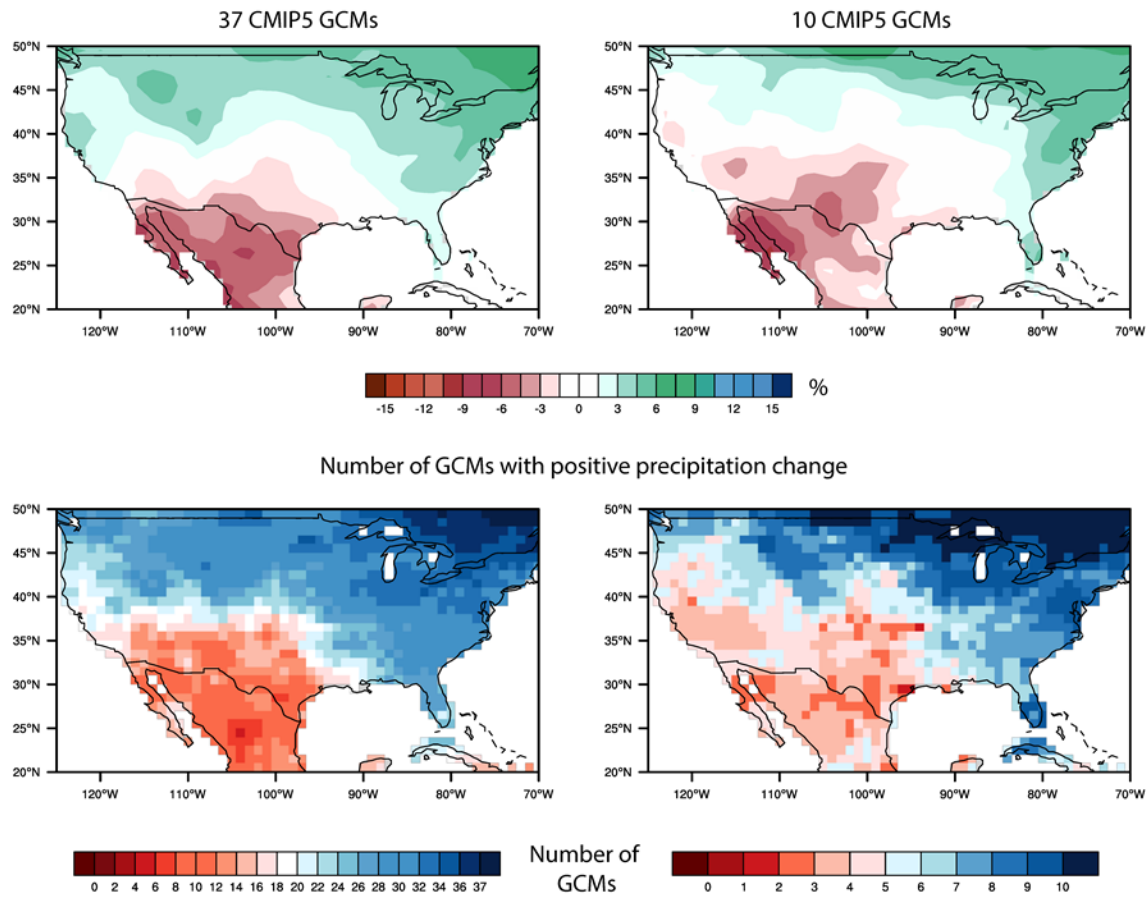


Fig. 2.3. Comparison of annual precipitation changes in selected GCMs with the larger CMIP5 ensemble.

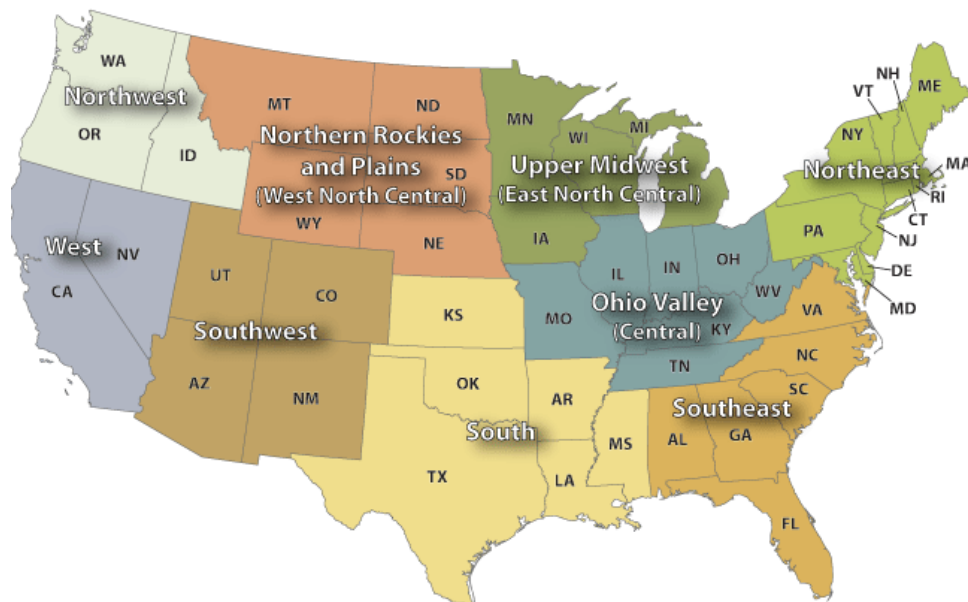


Fig. 2.4. Climate regions used for comparison of GCM and RCM data.

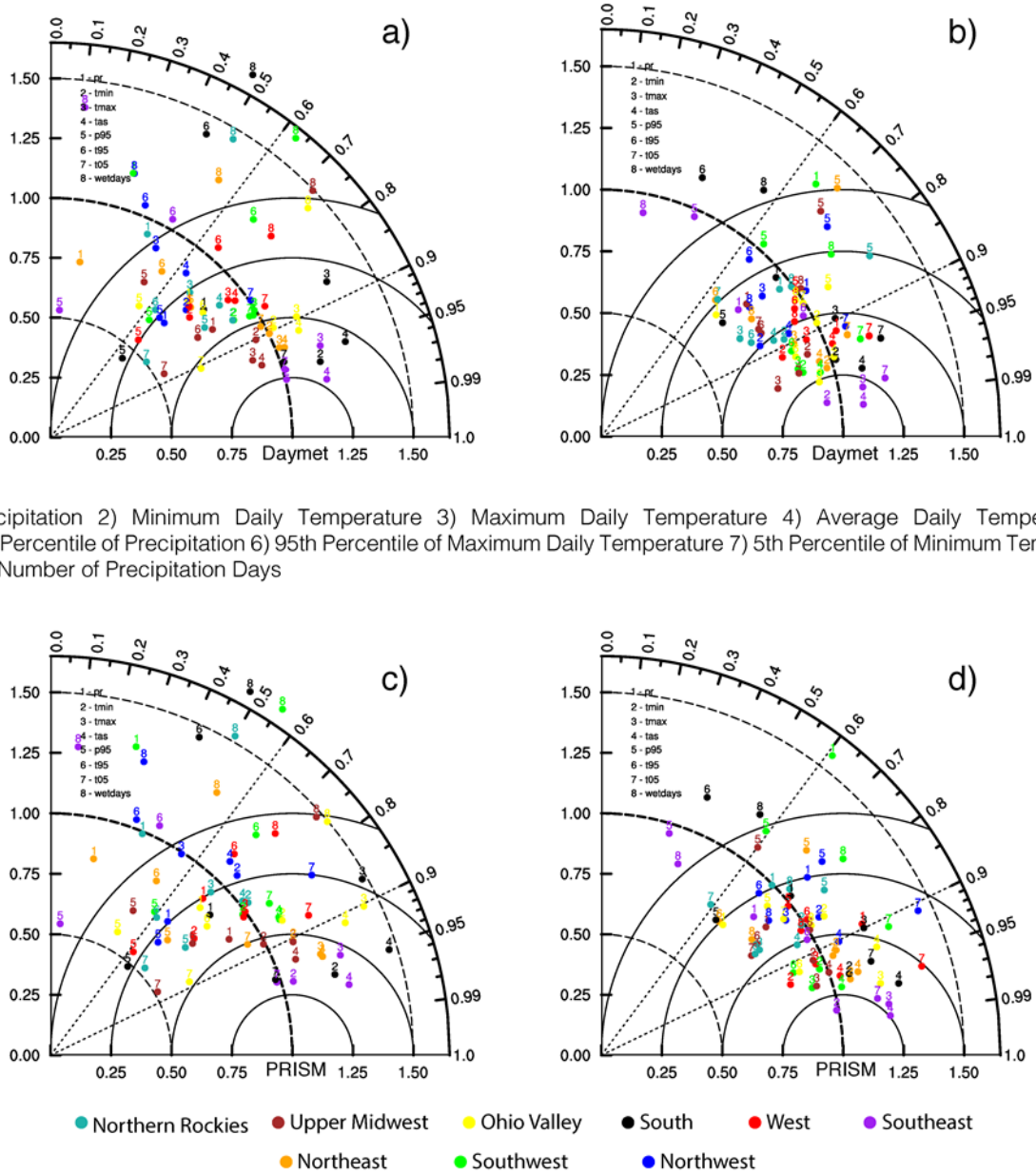


Fig. 2.5. Comparison of simulation skill in the selected GCM ensemble and the downscaled RCM ensemble.

In both comparisons, the RCM ensemble shows a substantial reduction of large-scale biases and improvement in the representation of fine-scale variability. In the case of the GCM ensemble, large errors in the ROV and RSMD were exhibited for temperature and precipitation extremes over most regions. Similarly, pattern correlation for hot temperature extremes and wet days was below 0.6 in most cases and was between 0.5 to 0.9 on average across all variables. The high-resolution RCM ensemble exhibited an improvement in characteristics of both mean and extreme temperature and precipitation over all regions. For instance, on average, the pattern correlation was between 0.6 to 0.95 across all variables. Similarly, errors in ROV and RSMD for extreme temperature and precipitation were relatively lower than those in the GCMs ensemble. An

improvement in two out of three (ROV, RSMD and pattern correlation) characteristics was observed for 90% of the comparisons in the RCM ensemble. These results not only highlight the added value in the high-resolution RCM ensemble, particularly in the simulation of extreme temperature and precipitation thresholds, but also demonstrate the overall usefulness of the modeling approach adopted for this impact assessment. For the subsequent analysis, RCM ensemble data were further downscaled to $1/24^\circ$ (~ 4 km) through a combination of statistical bias correction and hydrological modeling. Given that most hydrologic models are highly sensitive to minor variations in meteorological forcings, several studies have suggested that statistical bias correction should be performed on dynamically downscaled simulated precipitation and temperature before conducting a hydrologic simulation for better accuracy and lower bias (Rojas et al. 2011, Muerth et al. 2013, Ashfaq et al. 2010, Ahmed et al. 2013). Ashfaq et al. (2010) showed that running a hydrologic model forced with RCM simulations and without bias correction resulted in overestimations of soil moisture, baseflow, and surface runoff in the southeastern US. These results also showed a substantial improvement in the hydrological projections after performing statistical bias correction of temperature and precipitation. However, by definition, statistical bias correction is not capable of enhancing the spatial details of a climate change signal calculated as a difference between the future and baseline integrations. Therefore, statistical bias correction without process-based dynamical downscaling will limit the ability to understand regional-to-local scale hydro climatic feedbacks resulting from fine-scale climate change.

The bias correction was applied to the monthly precipitation and maximum/minimum surface temperature from the RegCM4 simulations using the meteorological observation described in Section 2.2. First, using the inverse distance weighting method (similar to Wood et al. 2002), RegCM4 data were interpolated to the PRISM $1/24^\circ$ geographical grid. The 1966–2005 monthly total precipitation and monthly average maximum/minimum daily temperature from the PRISM was used as the historic observation to support bias correction. Given that part of the Pacific Northwest watersheds are located in Canada and are not covered by PRISM, the $1/16^\circ$ (~ 6 km) resolution gridded observation from Hamlet et al. (2013) were regridded into $1/24^\circ$ (~ 4 km) resolution. For watersheds in Mexico that flow into the Rio Grande River basin, the $1/8^\circ$ (~ 12 km) resolution (Maurer et al. 2002) precipitation and temperature were regridded using inverse distance weighting method to a consistent $1/24^\circ$ (~ 4 km) domain for bias correction of this region. The bias correction was applied to each monthly quantile of precipitation and temperature in each calendar month of the baseline and future periods. In the baseline period, for a given ensemble member, the bias correction corrected each quantile of each calendar month in the simulated time series by mapping it to the corresponding observed quantile. For instance, the warmest January in the simulated data was corrected by the warmest January in the observed data, the warmest February in the simulated data was corrected by the warmest February in the observed data, and so on for all minimum and maximum temperature quantiles of all 12 calendar months. Similarly, the wettest January in the simulated data was corrected by the wettest January in the observed data, the wettest February in the simulated data was corrected by the wettest February in the observed data, and so on for all precipitation quantiles of all 12 calendar months.

In the future period, the change in the magnitude of each quantile (quantile shift) was first calculated in each calendar month as a difference (future minus baseline) for minimum and maximum temperature and as a ratio (future divided by baseline) for precipitation. The bias-corrected future period quantiles were then generated by adding the quantile shifts to the bias-

corrected baseline quantiles in the case of minimum temperature and maximum temperature and by multiplying the quantile shift by the bias-corrected baseline quantiles in the case of precipitation. For instance, the temperature differences between the maximum January value in the future period and the maximum January value in the baseline period were added to the maximum January value in the bias-corrected baseline period. Similarly, the ratio between the wettest January in the future period and the wettest January in the baseline period was multiplied by the wettest January value in the bias-corrected baseline period. The monthly correction was then distributed from each bias-corrected month to the model-simulated daily time series so that the daily distribution was maintained, but the aggregate was equal to the bias-corrected monthly mean. This bias correction methodology greatly improved the hydrologic simulation of the historical period relative to that derived using observational daily-scale climate inputs, both by correcting systematic errors in the absolute magnitude of the simulated temperature and precipitation inputs and by improving the spatial detail of the simulated inputs. It should be noted that this bias correction maintains the changes in temperature and precipitation simulated by the regional climate model. Further details of bias-correction are described in Ashfaq et al. (2010) and Sale et al. (2012).

2.3.3 Climate Projection Limitations

In addition to the strength and limitations discussed in the various referred literatures, some major limitations related to climate projection are summarized in this section:

- While global climate modeling associated with further dynamical/statistical downscaling may provide the most scientifically defensible climate projections, it should not be considered an absolute day-to-day weather prediction into the future. The main purpose of climate modeling is to simulate how general climate statistics may evolve with respect to the specified future emission scenarios, not to provide an exact prediction of future weather and hydrologic conditions.
- Given the large climate system variability, a large climate model ensemble (with various models, initial conditions, and long-term simulation) will be required to capture the overall mean and variability. Depending on the region and variables of interests (e.g., temperature versus precipitation), the required size of an ensemble could be vastly different. Nevertheless, such quantitative measure has not been fully understood in the current state of climate science.
- While a variety of downscaling techniques have been extensively used in various hydroclimate impact studies, a consensus on the best downscaling practice has yet to be reached. These different downscaling approaches would inevitably add a layer of uncertainty and complexity to projected future climate conditions. This is another open scientific challenge in the current climate science.
- Although the capabilities of GCMs have been continuously improved through the years, there are still a lot to be done. For instance, while human activities play an important role in the Earth system environment, many of the GCM simulations were conducted without considering the potential human influence on the land use land cover change and surface

hydrologic alterations. Therefore, recurring climate impact assessments based on the best available climate science remain necessary.

2.4 Hydrologic Modeling

Taking daily temperature, precipitation, and wind speed as inputs, the purpose of hydrologic modeling was to simulate how a watershed would respond (i.e., in terms of runoff, evapotranspiration) to the given meteorological forcing. In this subsection, the selected hydrologic model is introduced, and its implementation, calibration, and validation are described. The model sensitivity to changes in precipitation and temperature is also tested and discussed.

2.4.1 Hydrologic Model Description

The widely used semi-distributed Variable Infiltration Capacity (VIC) model (Nijssen et al. 1997, Liang et al. 1994 and 1996, Cherkauer et al. 2002) was used to translate the projected meteorological signals (e.g., precipitation, temperature, and wind) into hydrologic responses. VIC is a process-based hydrological model that simulates evapotranspiration, snow pack, surface runoff, baseflow, and other hydrologic mechanisms within a watershed. Every grid cell in the VIC model accounts for subgrid variability in soil, vegetation, precipitation and topography. The water and energy balances are solved for multiple elevation bands and vegetation types, which allows the model to capture the subgrid variability of these land surface features. The infiltration and runoff are estimated using the variable infiltration capacity curve, which uses the soil moisture content of the upper two soil layers to approximate the spatial variability of surface saturation. The empirical Arno curve is used to generate baseflow based on the soil moisture content in the bottom layer (Cherkauer and Lettenmaier 2003). While VIC is basically a one dimension model that solves mass and energy balance in the vertical direction, an external two dimensional horizontal routing algorithm can be used to estimate streamflow at a specified location (Lohmann et al. 1998). The VIC model has been adopted in many hydroclimate studies (Gao et al. 2010, Ashfaq et al. 2010, Su et al. 2005, Nijssen et al. 1997 and 2001, Bowling et al. 2004, Lohmann et al. 1998, Brekke et al. 2010, Gangopadhyay and Pruitt 2011), and it is also used in the previous 9505 assessment (Sale et al. 2012). The general model performance across various HUC8 subbasins in the CONUS can be found in Oubeidillah et al. (2014) and Naz et al. (2016).

2.4.2 Hydrologic Model Implementation

In order to study the large-scale climate change effects on various river systems across the US, in this study the VIC model was implemented for the entire CONUS at a refined $1/24^{\circ}$ (~ 4 km) grid resolution. In addition to the enhancement of spatial resolution from $1/8^{\circ}$ (~ 12 km) in the previous 9505 assessment (Sale et al. 2012), several key VIC model inputs, including soil, vegetation, and elevation, were recollected from multiple data sources. Computationally intensive calibration was then performed to increase the model accuracy. These new modeling features are briefly described in this section. Readers are referred to Oubeidillah et al. (2014) and Naz et al. (2016) for more technical details.

- *Soil parameters:* For soil physical properties, the CONUS-SOIL information was aggregated into three layers covering total depth from 0 to 2.5 m (CONUS-SOIL layers 1 and 2 to VIC model layer 1, CONUS-SOIL layers 3–7 to VIC model layer 2, and CONUS-SOIL layers 8 and 9 to VIC model layer 3) to help select VIC soil parameters. When a three-layer configuration is used, a total of 53 soil parameters is required, including saturated hydrologic conductivity, initial soil moisture, bulk density, layer thickness, fraction of soil moisture at wilting point, and some other conceptualized parameters. A few other non-soil parameters required in the VIC soil parameter file, such as the average annual air temperature, average annual precipitation, average elevation, and slope (used to derive the maximum velocity of the base flow), were derived from Daymet and NED. If the CONUS-SOIL information was unavailable for a specific grid point, the information from the nearest grid point was used instead. For non-US regions without CONUS-SOIL info, the Nijssen et al. (2001) modeling parameters were used for further model calibration.
- *Vegetation parameters:* For vegetation, the VIC parameter file describes the number and percentage of vegetation types in each grid cell. To enhance the characterization of surface vegetation, the MODIS 15A2 LAI observation was organized for each $1/24^\circ$ (~ 4 km) grid for the entire CONUS. The monthly MODIS LAI observation was first averaged across 2003–2008 at the original 1 km grid and then converted to the subgrid VIC vegetation format for simulation. It should be noted that the current VIC does not support dynamic vegetation simulation, so the seasonal LAI variability will be fixed annually following the specified monthly LAI values (even under future climate conditions). This is one simplification of the current model.
- *Snow elevation bands:* To represent snow accumulation and snowmelt, subgrid snow elevation bands were set up in this study. Snow elevation bands are used to create parallel subgrid computational units with different elevations to provide more accurate simulation of snow. Using the histogram derived from ~ 10 m NED (or ~ 90 m SRTM) in each $1/24^\circ$ (~ 4 km) grid, the average elevation was calculated for each 20% of sorted subgrid cells to form five equal area elevation bands for simulation. Although increasing the number of snow elevation bands can ideally improve the simulation of snow, it also raises the computational demand rapidly (i.e., VIC computational time is approximately proportional to the number of bands). In this study five snow elevation bands were used consistently for the entire CONUS.

VIC version 4.1.1 was used in this study. To manage the large amount of data (i.e., around a half million grid points in the US), all forcing, soil, vegetation, global parameter, and output flux files were organized by HUC8 subbasins. The average number of grid points is around 232 per HUC8, but the actual number varies proportional to the sizes of HUC8, from 2 points to over 1,200 points. Depending on the total watershed area, all grid cells within a HUC8 are subdivided into 16, 32, or 48 computation units for parallel computing. Computation was performed using ORNL's Titan supercomputer, a Cray XK7 system with 18,688 computational nodes, each equipped with four quad-core central processing units (CPUs) and two graphics processing units (GPUs) cards. This computational setup allowed for more efficient calibration of the model and simulation of hydrologic projections. With the increased spatial resolution, the VIC model could handle more detailed inputs of topography, land uses, soil characteristics, as well as temperature and precipitation that may vary significantly, particularly in the mountainous regions.

2.4.3 Hydrologic Model Calibration and Validation

Although VIC is a process-based model that includes various explicit physical mechanisms, some processes still rely on conceptual statistical parameterization. As a result, several conceptual parameters require further calibration. Calibration is also required for parameters with higher measurement uncertainties (e.g., soil parameters). Following the sensitivity analysis by Demaria et al. (2007), six sensitive VIC parameters were selected for calibration, including the variable infiltration curve parameter ($b_{infiltr}$), exponent of the Brooks–Corey drainage equation (exp), thickness of soil layer 2 ($thick_2$) and layer 3 ($thick_3$), fraction of the maximum velocity of base flow at which nonlinear base flow begins (Ds), and fraction of maximum soil moisture at which nonlinear base flow occurs (Ws). Although the soil parameters are obtained with a pre-specified soil depth, the thicknesses of soil layers 2 (root layer) and 3 are treated as parameters and can be adjusted during calibration.

Calibration was performed by minimizing the difference between the simulated total monthly runoff (baseflow + surface runoff) and the WaterWatch monthly runoff. Given that WaterWatch runoff is found to be the most significant variable in explaining historic annual hydropower generation (Sale et al. 2012), calibrating VIC to WaterWatch helped enhance the accuracy of the subsequent hydropower simulation (Section 2.5). The control simulation was driven by the Daymet/PRISM daily meteorological forcing (precipitation and minimum/maximum temperature) and NARR daily wind speed from 1980 to 2012. Year 1980 was treated as the model startup period, 1981–2000 as the calibration period, and 2001–2012 as the validation period. Calibration was based on the initial parameters identified by Oubeidillah et al. (2014) with enhancement on HUC8s with lower model accuracy (Naz et al. 2016). Since WaterWatch did not explicitly exclude gauges that were under flow regulation, it cannot fully represent the natural runoff observation (i.e., without human influence). Further efforts can be made to replace the regulated gauge observations in the WaterWatch with naturalized flow estimates to remove the effects of human influence and to improve the VIC calibration to better represent the natural hydrologic system.

The overall performance is shown in Fig. 2.6 and Fig. 2.7. In Fig. 2.6, the observed versus simulated annual average total runoffs from each HUC8 are compared for (a) the 1981–2000 calibration period, (b) the 2001–2012 validation period, (c) the results from the previous 9505 assessment (Sale et al. 2012), and (d) the initial results organized by Oubeidillah et al. (2014). Both calibration and validation periods show similarly good results with coefficient p close to 1. With the intensive model calibration, the accuracy of VIC has been largely improved relative to the previous 9505 assessment (p increases from [c] 0.878 to [d] 0.971). The wet bias reported by Oubeidillah et al. (2014) in some of arid HUCs in the central U.S. was also reduced (i.e., narrower scatter pattern of HUCs with annual total runoff less than 300 mm). The geographical features and some commonly used performance metrics, including R^2 , Nash Sutcliffe coefficient, mean absolute error (MAE), and root mean square error (RMSE), are further illustrated in Fig. 2.7 (corresponding to Fig. 2.6(a) results). For each HUC8 subbasin, the 1981–2000 simulated and observed monthly total runoff time series were used for evaluation. In general, the model closely simulates observed monthly runoff for many HUC8s across the US. In terms of R^2 and Nash Sutcliffe coefficient, HUCs in wetter regions perform better than drier regions. Despite having lower R^2 and Nash Sutcliffe coefficient, the arid regions generally had lower MAE and RMSE, so the influence on overall water budget error was somewhat reduced. Given the strong

correlation between runoff and historic regional hydropower generation (Kao et al. 2015), calibration of runoff was expected to benefit the follow-up hydropower simulation.

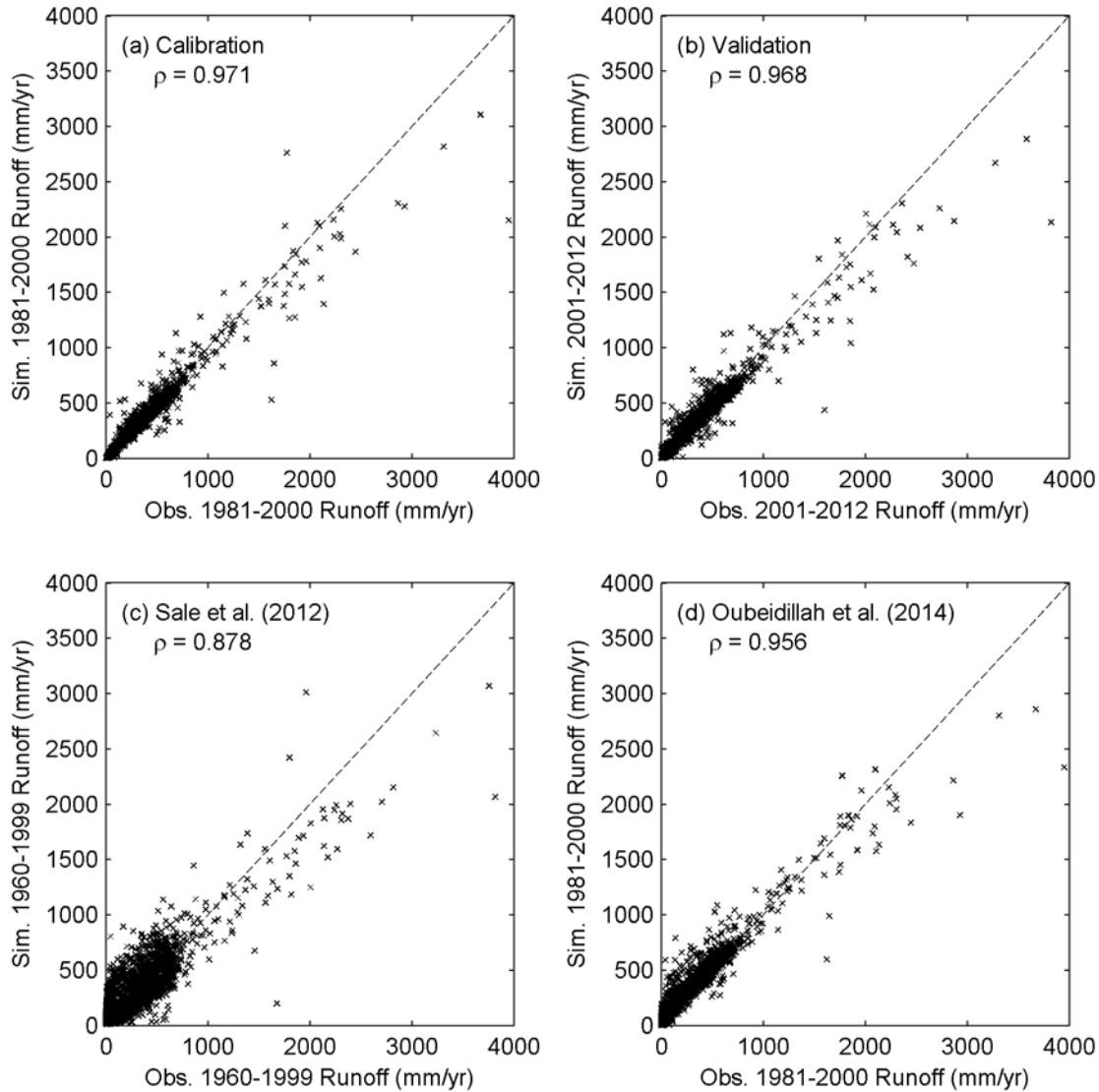


Fig. 2.6. VIC model performance. The observed versus simulated average total annual runoffs from each HUC8 are illustrated for (a) 1981–2000 calibration period, (b) 2001–2012 validation period, (c) results from the previous 9505 assessment (Sale et al. 2012), and (d) the initial results reported by Oubeidillah et al. (2014)

To further evaluate the model performance for snow variables, the simulated April 1st SWE was compared with the SNOTEL observed snow course data as described in Mote et al. (2005) in the western US. Focusing on the 1981–2000 period, 784 snow stations with complete annual April 1st SWE observations were selected. For each station, the simulated April 1st SWE at the nearest grid was looked up. Since the point observation may be on a different scale from the grid-based

SWE, the correlation coefficient between observation and simulation was computed for evaluation. The results are summarized in Fig. 2.8 (similar to Fig. 13 in Oubeidillah et al. [2014] with updated parameters). In Fig. 2.7, correlation coefficients between observed and simulated 1981–2000 April 1st SWE were computed for 784 selected stations. Fig. 2.8a plots the histogram of ρ and shows that high correlation coefficients can be seen in most stations. To examine the statistical significance, the histogram of the P value is plotted in Fig. 2.8b. The P value was less than 0.05 for nearly 700 stations (i.e., correlation is statistically significant at the 5% significance level), which suggests that the simulation captured the interannual variability for most of the stations. To check the spatial pattern, ρ values are further plotted in Fig. 2.8c. The simulated SWE generally showed good correlation with observations for most of the stations.

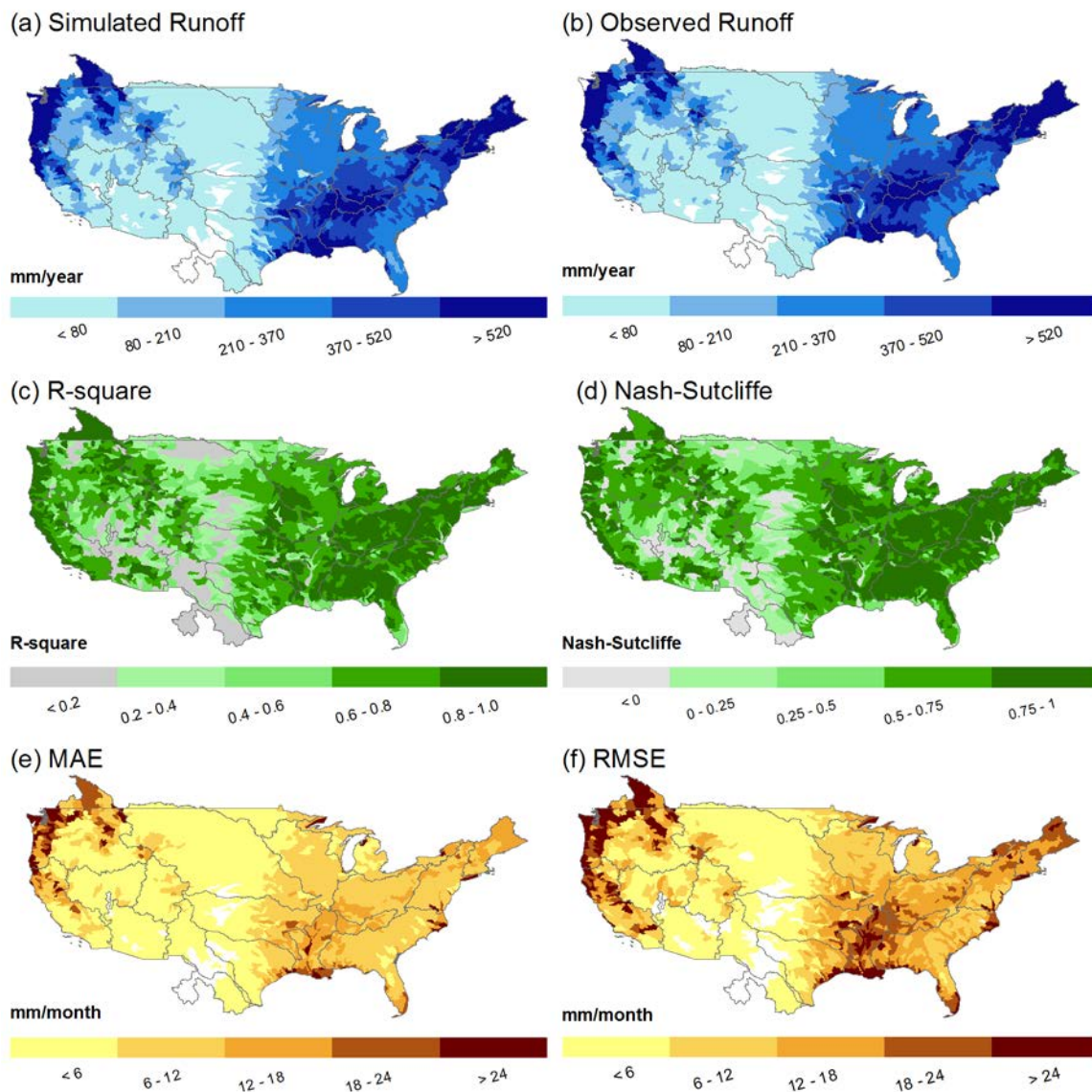


Fig. 2.7. Performance of VIC model at various HUC8s in the conterminous US.

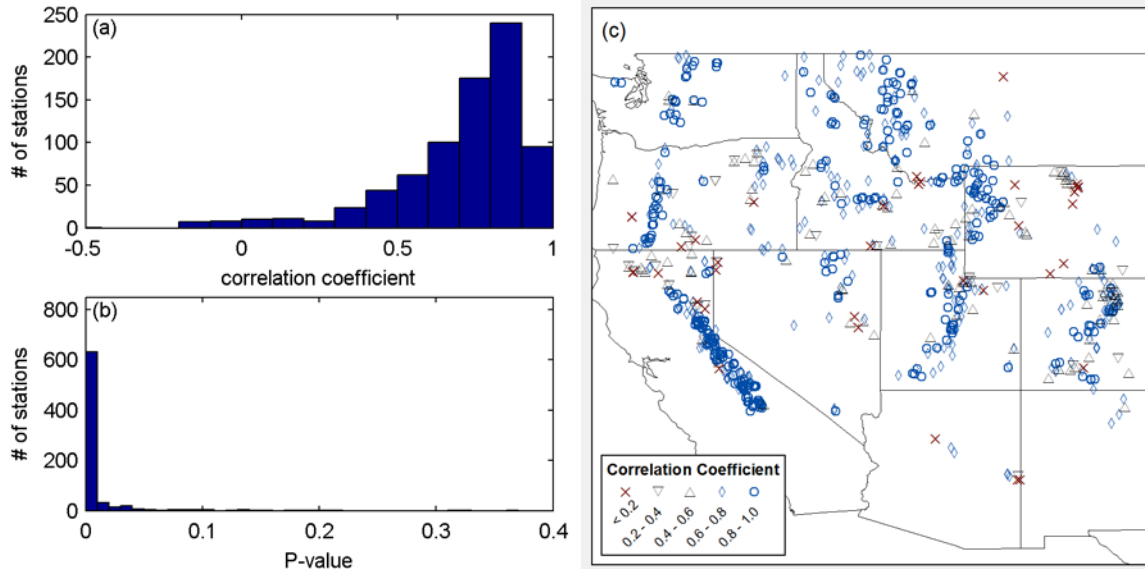


Fig. 2.8. Performance of snow simulation: (a) histogram of correlation coefficients; (b) histogram of P-value; (c) spatial pattern of temporal correlation coefficients for all selected stations.

2.4.4 Hydrologic Model Sensitivity to Changes in Precipitation and Temperature

To test the response of the VIC model to changes in precipitation and temperature, a sensitivity analysis was performed. Based on the setup of the 1980–2012 control run, three sets of simulations were selected (following the discussion with Reclamation staff): (a) 1° C degree increase in both historic maximum and minimum daily temperature, (b) 10% increase in historic precipitation, and (c) 10% decrease in historic precipitation. The percentage change in mean annual runoff was then calculated for each HUC8 and plotted as probability densities across all HUC8s in the US. As shown in Fig. 2.9, the simulated percentage change in mean HUC8 annual runoff as the result of +1° C varied from 0% to -15%, with the median around -3%. As with precipitation, a +10% precipitation scenario resulted in +5% to +70% increase in runoff with a median around +22%, whereas a -10% precipitation scenario resulted in -5% to -60% decreases in mean annual runoff with a median around -21%.

In terms of precipitation elasticity (ϵ), which is defined as the fractional change in runoff per fractional change in precipitation ($\Delta \% \text{ runoff} / \Delta \% \text{ precipitation}$) (Sankarasubramanian et al. 2001), most of the HUC8s fell between 1.0 to 4.0 (i.e., a 10% change in mean annual precipitation results in a 10–40% change in mean annual runoff). This result is on the same order of magnitude with other studies: from 1.0 to 2.5 over the US (Sankarasubramanian et al. 2001), from 2.0 to 6.0 for different land surface models in the Colorado River (Vano et al. 2012), and from 1.0 to 3.0 at global scale Tang and Lettenmaier (2012). This suggests that the VIC model established in this study should have similar sensitivity to temperature and precipitation variation with other studies. Nevertheless, to fully quantify the entire spectrum of sensitivity, further scenarios should be explored in future assessment (e.g., +2° C temperature and/or +/- 5% precipitation) given the nonlinear nature of the model.

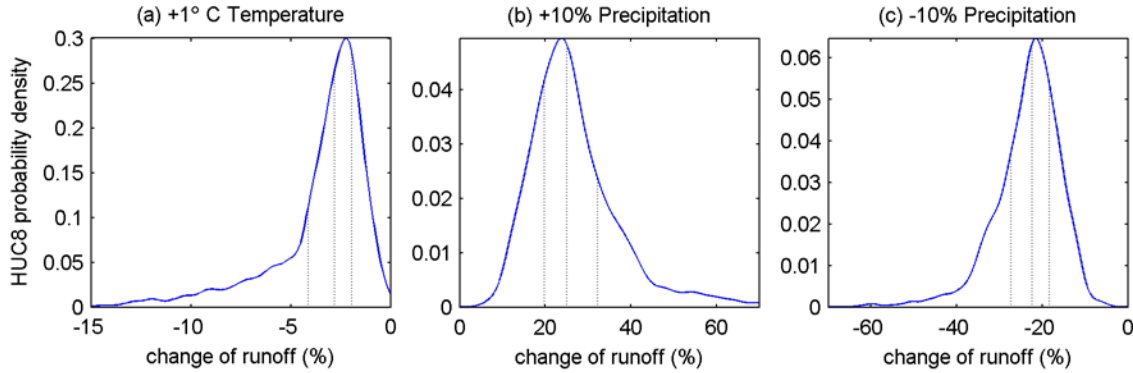


Fig. 2.9. VIC runoff sensitivity: (a) 1° C increase in historical temperature, (b) 10% increase in historical precipitation and (c) 10% decrease in historical precipitation scenarios is calculated for each HUC8s in the conterminous US. Dash lines indicate the 25th, 50th, and 75th percentiles of the distributions.

2.4.5 Downscaled Hydrologic Simulations

To characterize the hydrologic response to climate change in each assessment area, the bias-corrected daily precipitation, minimum and maximum temperatures, and unadjusted wind speed data from 10 RegCM4 runs were used as inputs to drive the calibrated VIC model for baseline (1966–2005) and future time periods (2011–2050). To evaluate if the simulated runoff (driven by RegCM4-based forcings) was consistent with the observed USGS WaterWatch runoff, the monthly average runoff during the overlapping historical time period (1981–2005) was calculated for each HUC8 and summarized as cumulative probability distributions illustrated for each 2-digit hydrologic region (HUC2) in Fig. 2.10. Overall, the magnitude of RegCM4-simulated monthly average runoff was reasonably simulated in all regions when compared with control run runoff and the observation-based runoff. Regionally, the RegCM4-simulated runoff showed a wet bias in the eastern regions (Regions 1, 2, and 3) relative to the observation-based runoff and control run historic-simulated runoff (Fig. 2.10a-c). This wet bias was more evident in Regions 2 and 3. In the midwest regions (i.e., 4, 5, 7, and 9), the RegCM4-simulations underestimated the monthly runoff relative to the observations and control run, although high flows are overestimated in Region 9. This dry bias is much greater for the upper Mississippi basin (Region 7). Similarly, a dry bias was observed in the southwestern regions (i.e., Regions 13, 14, 15, and 16). It is most likely that these biases result either from the seasonal and spatial patterns or interannual variability in the RegCM4 precipitation and temperature data.

2.4.6 Hydrologic Model Limitations

Some major hydrologic model limitations for the purpose of hydro-climate impact assessment are summarized and discussed in this section.

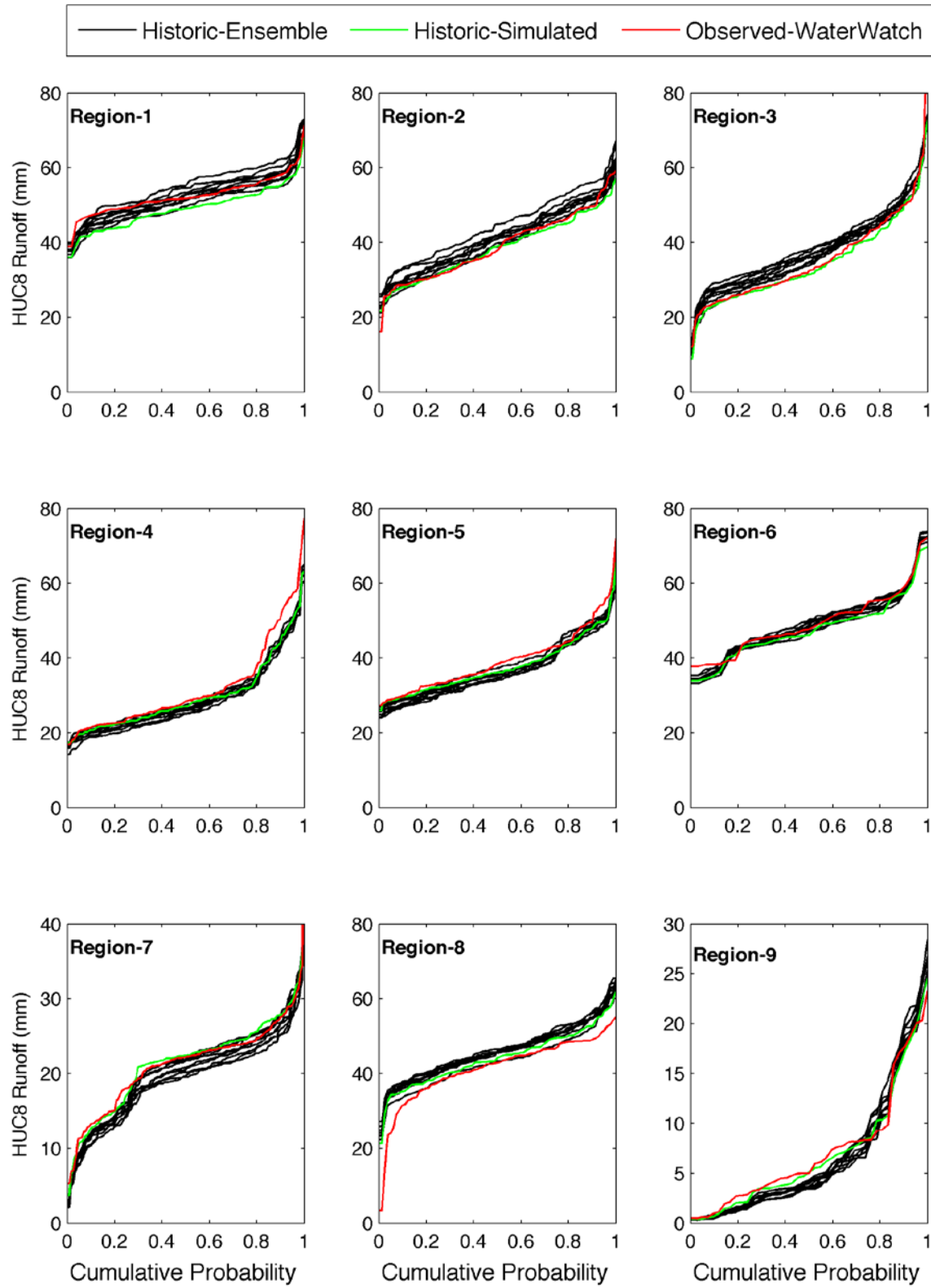


Fig. 2.10. Cumulative distribution functions of the downscaled, simulated mean monthly runoff for the 1981–2005 period and compared with historical simulated and observed monthly runoff.

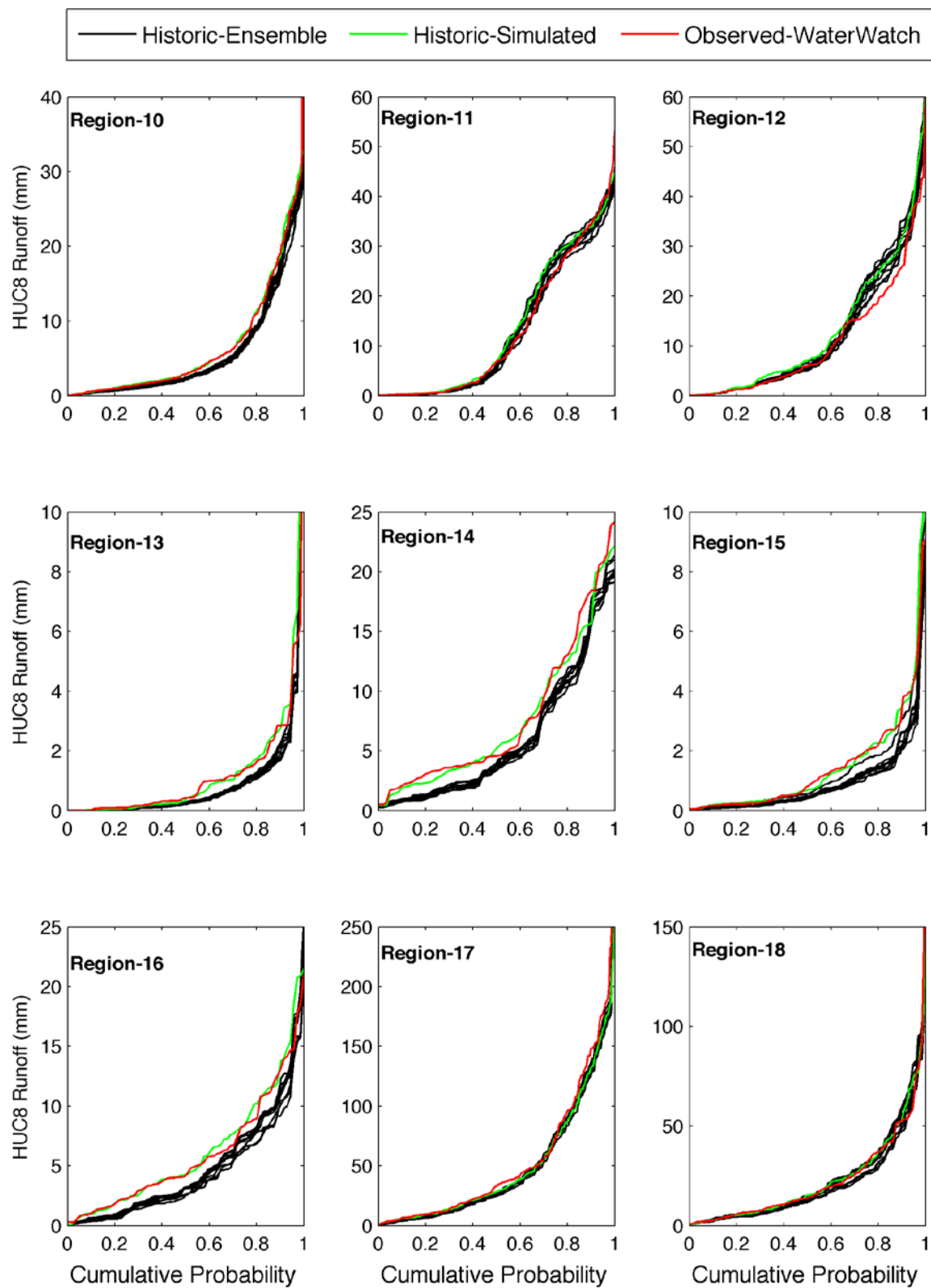


Fig. 2.10. Cumulative distribution functions of the downscaled, simulated mean monthly runoff for the 1981–2005 period and compared with historical simulated and observed monthly runoff (continued).

- Similar to the additional uncertainty introduced by different downscaling techniques, the selection of hydrologic models could also result in undesirable uncertainty in the future hydro-climate projections. However, there is only limited understanding regarding the selection of suitable hydrologic models and physical processes for hydro-climate impact assessment. This open scientific challenge is yet to be fully explored.
- Simply focusing on one selected hydrologic model (e.g., VIC used in this study), the different hydrologic model parameters determined through different calibration procedures could alter the values of future hydro-climate projections. Similarly, choices of model configurations such as resolutions, parameterizations, model versions, and other modeling options are also factors of considerations. Whether these intermodel differences may significantly alter future hydro-climate projections remains to be explored.
- While the USGS WaterWatch runoff data set can be used to efficiently calibrate VIC parameters for the entire CONUS, it cannot fully represent the natural runoff observation (i.e., without human influence). Since some gauges used by WaterWatch are under flow regulation, the computed runoff can be biased in basins with significant historical impairments. Further efforts can be performed to replace the regulated gauge observations in the WaterWatch with naturalized flow estimates to remove the effects of human influence and to improve the VIC calibration.
- Although the VIC model can provide satisfactory performance for the purpose of this study, it does not have a robust groundwater component. Therefore, for basins with strong surface-groundwater interactions, performance of the VIC model can be hindered. Other alternative hydrologic models with the groundwater component can be considered in a future assessment.

For each PMA study area, the effects of future changes in major hydroclimatic variables, including temperature (T), precipitation (P), evapotranspiration (E), total runoff (Q, sum of both VIC surface runoff and baseflow), and SWE were analyzed (presented in Sections 3–6). Except for SWE, the simulated data (i.e., T, P, E, and Q) were first summarized for each PMA region by calculating the average daily time series for each model run and for baseline (1966–2005), near-future (2011–2030), and midterm future (2031–2050) periods. The projected changes in mean annual, spring (March–April–May [MAM]), summer (June–July–August [JJA]), fall (September–October–November [SON]), and winter (December–January–February [DJF]) temperature, precipitation, evapotranspiration, and runoff changes from baseline to future periods were estimated for each model. The ensemble minimum, median, and maximum across the 10 selected models were then plotted. In addition, the monthly multi-model 10th, 50th, and 90th percentiles for temperature, precipitation, evapotranspiration and total runoff were also plotted for the baseline and two future periods.

In addition, the change in extreme runoff conditions (high and low runoff) was plotted for the future projections (presented in Sections 3–6). High-runoff (R95) was defined as the 95th percentile of daily runoff, whereas R5 was defined as the 5th percentile of the running 7-day average runoff (note that a cumulative 7-day window was used to smooth out the fluctuations during the low runoff period) for every grid cell in each PMA area. The annual percentage

change (future minus baseline) in the high-runoff and low-runoff was then calculated for each grid cell.

For the projected change in snow conditions, the relative change in average April 1st SWE, absolute difference (future minus baseline) in number of snow-covered days (i.e., the number of days when the SWE is greater than 5mm on the ground) and percentage change (future minus baseline) in the annual maximum SWE was calculated separately for each model run and shown as multi-model median distribution for each PMA study area (Fig. 2.11). For the snow variables, all grid cells where the long-term (i.e., average across the 1980–2012 control run) April 1st SWE is greater than 5mm were first identified. The identified grid cells were then used as a spatial filter to summarize the simulated April 1st SWE, snow-covered days, and annual maximum SWE for each model and for baseline and future periods across all PMA study areas.

In addition to the summarized future hydro-climate projections made in this study, results from some other existing literatures in each PMA region were also summarized and quantitatively / qualitatively discussed in each PMA section. Further information can be found in Sections 3-6.

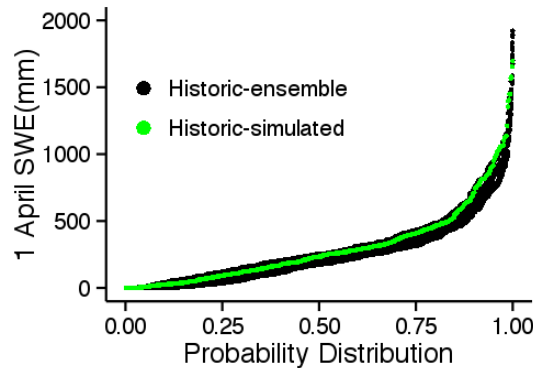


Fig. 2.11. Cumulative distribution functions of the downscaled, simulated mean April 1 SWE for the 1981–2000 period and compared with historical data simulated in the highest elevation band within 784 VIC grid cells located near SNOTEL stations.

2.5 Hydropower Simulation

Following hydrologic modeling, the modeled runoff at this stage reflects the direct watershed response to natural forcing (e.g., precipitation, temperature) without considering manmade alteration such as withdrawal, diversion, or reservoir retention (i.e., natural runoff). In reality, these fresh water resources are further used (or regulated) for irrigation, domestic/industrial water usage, hydropower generation, power plant cooling, and flood risk management through hydraulic infrastructures such as dams, canals, and penstocks. Therefore, in order to study the likely hydropower generation under future climate change conditions, an energy-water relationship is required to translate the natural runoff and streamflow into hydroelectric energy potential. This can be achieved by feeding the simulated streamflow into a reservoir management model to simulate water release, reservoir storage, and hydropower generation under various operation rules (e.g., Yao and Georgakakos 2001), or by using a simplified statistical relationship to study the regional hydropower generation directly (e.g., Kao et al. 2015). Given the need to evaluate climate change effects comprehensively for 132 federal hydropower plants across the

nation, a lumped Watershed Runoff-Energy Storage (WRES) model is designed for this study. The model assumptions, details, and validation are described in this subsection.

2.5.1 Background of Energy-Water Modeling

To study the impacts of climate change on hydropower generation, progress has been made on smaller systems with a limited number of hydropower plants. Robinson (1997) used a reservoir depletion model to study how the hydropower systems of Duke Power and Virginia Power in the southeastern US might react to a 2° C increase in temperature and a 10% decrease in precipitation. Mimikou and Baltas (1997) used a runoff-based water balance model with three GCM-derived future climate scenarios to study the sensitivity of annual hydroelectric energy production of a large multipurpose reservoir in northern Greece. Christensen et al. (2004) analyzed the effect of climate change on the water resources of the Colorado River Basin in the US using three downscaled climate projections generated from one GCM. Vicuna et al. (2008) used a linear programming model with four GCM-driven scenarios to investigate how climate change may impact an 11-reservoir system in the Upper American River Basin in California. Hamlet et al. (2010) used two climate scenarios and a Columbia Simulation reservoir model (Hamlet and Lettenmaier 1999) to evaluate the potential effects of climate change on seasonal and annual hydropower generation from 20 selected major reservoirs in the Columbia River Basin in the Pacific Northwest. Other studies related to the assessment of climate and hydropower were reported by Yao and Georgakakos (2001), Harrison and Whittington (2002), AEG and Cubed (2005), Tanaka et al. (2006), Schaeffli et al. (2007), and Markoff and Cullen (2008). While the findings of these studies varied depending on the characteristics of the hydropower systems and also the selection of future climate change scenarios, several studies have suggested that systems with less storage capacities could be more vulnerable to the potential future climate change. While these studies have laid foundations for examining climate change impacts on selected hydropower plants, assessing impacts across large spatial scales remains a major challenge.

In general, various models and software can be used to simulate reservoir operations for flood operation, hydropower generation, environmental protection, low flow management and water supply for planning studies or real-time decision support, such as RiverWare (Zagona et al. 2001) and the Hydrologic Engineering Center Reservoir System Simulation (HEC-ResSim) model (Klipsch and Hurst 2013). These models are mostly reservoir-based, requiring detailed parameters including dam/reservoir characteristics, stage-volume-flow relationship, water demand information, and other time-variant operational constraints related to flood risk management, minimum flow requirement, and in-stream temperature tolerance for aquatic species protection at each reservoir. However, given the somewhat sensitive and proprietary nature of these basic energy-water infrastructures, data availability for model development, calibration, and validation remains one key challenge. For a complicated, interconnected, and multi-ownership system such as the Columbia and Colorado River Basins, creating an integrated energy-water model requires the collection of reservoir characteristics and operation rules for all reservoirs (including powered or non-powered and federal or nonfederal) in the system. In addition, although reservoir-based models may have existed and been used by water and energy managers for day-to-day operation, these models are likely constructed through nonuniform methods/tools that fit into their best site-specific needs but cannot be integrated directly. Many of the reservoir-based models are also designed for short-term forecasting or midterm resource

planning, and so they are not suitable for long-term climate change simulation. Therefore, given the finite resources for investigation, the bottom-up (i.e., reservoir-based) approach may not be the most feasible solution for a national-scale hydropower-climate change study.

Conversely, an alternative method is through a top-down approach via simplified empirical models for a large number of hydropower plants in a region. For instance, an energy flow method is used in the Energy-Based Hydropower Optimization Model (EBHOM) by Madani and Lund (2009 and 2010) to evaluate climate change impacts on more than 135 high-elevation hydropower plants in California. Markoff and Cullen (2008) used regression modeling to predict the average annual streamflow and hydropower generation from the winter/summer precipitation fraction and temperature change so that the assessment can be expanded to cover more climate change models. To study the climate change impacts on hydropower generation on a national scale, a regional regression approach was introduced by Sale et al. (2012) and Kao et al. (2015) to study the change of annual total hydropower generation for 132 hydropower plants in 18 federal hydropower study areas in the US. This type of top-down approach generally starts by developing a regional energy-water relationship using historic observations and then studying hydropower generation under future climate conditions. Implicitly, this approach assumes that the historic operations remain unchanged in the future so that the projected hydropower change only reflects the change of climate forcings without possible adjustment of operations. Since a primary objective of this study was to comprehensively examine this risk across the federal hydropower fleet, the top-down approach was used. This approach enables an overall view of the entire fleet while identifying areas that may require a more site-specific, operational study of the direct/indirect effects on hydropower production (potential methods for site-specific analysis are discussed in Section 2.7).

2.5.2 Hydropower Model Description

While hydropower operation decisions are mostly made on relatively short time scales (hourly, daily) using variables including water usage allocations, daily energy demand, pool elevation, turbine efficiency, flood risk management and environmental commitments, on longer time scales (annual and longer), water availability mainly dominates the amount of hydropower generation. Therefore, a runoff-energy regression approach was developed in the previous 9505 assessment (Sale et al. 2012) to simulate annual hydropower generation using annual or multi-year runoff from all contributing drainage areas. This linear relationship, while working properly at annual and multi-annual scales, cannot be extended to seasonal or monthly scales without considering the amount of water storage managed through all reservoirs and retention facilities in the watershed.

A lumped watershed runoff-energy storage (WRES) model was developed for the second 9505 assessment (schema shown in Fig. 2.12) to study how subannual hydropower generation may change in the future climate. Although various types of federal hydropower systems are associated with diverse hydrologic conditions and operational objectives, the WRES model was designed without site-specific operations in order to maintain an internally consistent modeling approach that isolated the effects of climate change on hydropower potential. For each hydropower region, the WRES model used the monthly precipitation and natural (unregulated) runoff as inputs, performed a runoff mass balance calculation for the total monthly runoff storage in all reservoirs and retention facilities in the watershed, and simulated the monthly regulated

runoff release and hydropower generation through the system. The required WRES model parameters, including initial, maximum / minimum monthly storage, and maximum runoff-hydropower capacity, were estimated for the historical period from 1980–2009. The calibrated model was then driven by the downscaled hydroclimate variables to project future hydropower generation, assuming that most of the reservoirs in the watershed will be operated in the same way in the future. Two main components in the WRES model are described below: (1) monthly generation prediction, and (2) watershed runoff storage calculation.

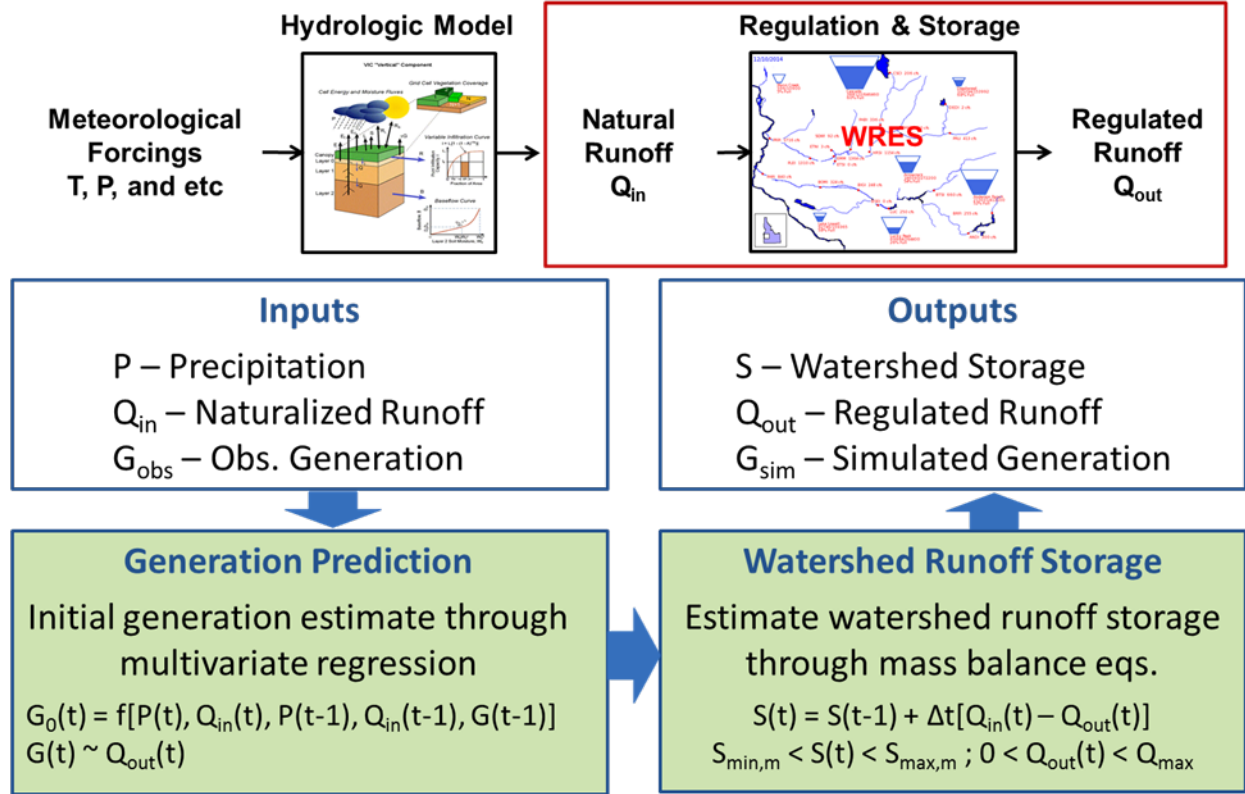


Fig. 2.12. Schema of WRES model.

- **Monthly Generation Prediction**

The first step of WRES simulation was to determine an initial estimate of total monthly hydropower generation G_0 (MWh/month) based on hydrologic inflow/outflow conditions (e.g., the amount of precipitation and runoff) and generation from previous time steps. After testing several combinations of variables and lag time, a generalized multivariate regression model with five predictor variables was used:

$$G_0(t) = b_{0,m} + b_{1,m} * P(t) + b_{2,m} * Q_{in}(t) + b_{3,m} * P(t-1) + b_{4,m} * Q_{in}(t-1) + b_{5,m} * G(t-1) \quad (2.1).$$

In Eq. (2.1), t is the time of calculation (in the unit of month), $m = \text{Jan, Feb, ..., Dec}$ represents which calendar month t belongs to, $P(t)$ and $P(t-1)$ are the monthly precipitation

(inch/month) from the current and previous months, $Q_{in}(t)$ and $Q_{in}(t-1)$ are the monthly natural runoff (inch/month) from the current and previous months, $G(t-1)$ is the monthly generation (MWh/month) from the previous month, and $b_{0,m}, b_{1,m}, \dots, b_{5,m}$ are the regression coefficients developed separately for each calendar month m . For a study area that is also located downstream from other study areas (e.g., BPA-3 is downstream from BPA-1 and BPA-2), P and Q were calculated from all upstream watershed areas before WRES simulation was conducted.

It is noted that although the total storage in watershed should be a useful variable to predict generation, it was not included in the multivariate regression formula since it is also a variable to solve in WRES. Instead, generation from previous time steps was included in the regression formula. Generation, precipitation, and runoff from previous time steps reflect the overall storage in the watershed and can replace the role of storage in the multivariate regression.

- **Watershed Runoff Storage Calculation**

While G_0 from Eq. (2.1) provides a likely generation estimate based on hydrologic inflow/outflow conditions (i.e., jointly captured by the five predictor variables), it may not be physically feasible during extremely wet or dry conditions. Most of the reservoirs follow the established operation curves in which seasonal maximum/minimum pool elevations are specified. During drought conditions, the storage in the system may be close to the minimum so that the water release and generation would be reduced for water conservation. Conversely, during wet conditions, the storage may approach a maximum capacity for flood risk management. Water release and hydropower generation will hence increase, and sometimes water is even spilled (i.e., not passing through hydropower turbines) during flood conditions. Given that an extreme hydrologic event is one of the main concerns of future water and hydropower operations, these storage limitations need to be addressed within the overall formulation.

In order to capture the maximum and minimum storage limitations in the watershed, a lumped runoff mass balance calculation was performed. Several conceptual watershed storage characteristics were defined, including maximum monthly watershed storage $S_{max,m}$ (inch), minimum monthly watershed storage $S_{min,m}$ (inch), and maximum runoff-hydropower capacity Q_{max} (inch/month). Four steps were included in the watershed runoff storage calculation:

- **Step 1 – Estimate runoff release and watershed storage.** Based on the linear relationship between runoff and hydropower generation (identified from the first 9505 assessment), it was further assumed that the monthly hydropower generation was highly associated with the monthly runoff release Q_{out} from the watershed. Therefore, G_0 can be transformed to a runoff release estimate $Q_{out,step1}$ (inch/month) by

$$Q_{out,step1}(t) = G_0(t)/a \quad (2.2),$$

where a is a conversion factor between Q_{out} and G . Through the concept of total runoff mass balance, the watershed storage is further estimated by:

$$S_{step1}(t) = S(t - 1) + Q_{in}(t) - Q_{out,step1}(t) \quad (2.3).$$

- **Step 2 – Revise based on the maximum/minimum watershed storage limitations.** The initial watershed storage estimate from step 1 is checked against $S_{max,m}$ and $S_{min,m}$. If the value exceeds watershed limitation, the targeted watershed storage and runoff release are revised:

$$\begin{cases} \text{If } S_{step1}(t) < S_{min,m}, & S_{step2}(t) = S_{min,m} \\ \text{If } S_{step1}(t) > S_{max,m}, & S_{step2}(t) = S_{max,m} \\ \text{Otherwise,} & S_{step2}(t) = S_{step1}(t) \end{cases} \quad (2.4).$$

$$Q_{out,step2}(t) = S(t - 1) + Q_{in}(t) - S_{step2}(t) \quad (2.5).$$

- **Step 3 – Check if negative runoff occurs.** Under extreme drought conditions, occasionally the runoff release from Step 2 can be negative. To avoid this potential issue, the following adjustment is performed.

$$\begin{cases} \text{If } Q_{out,step2}(t) < 0, & Q_{out}(t) = 0 \\ \text{Otherwise,} & Q_{out}(t) = Q_{out,step2}(t) \end{cases} \quad (2.6).$$

$$S(t) = S(t - 1) + Q_{in}(t) - Q_{out}(t) \quad (2.7).$$

- **Step 4 – Check if spill occurs.** Under high flow conditions, the amount of total runoff release Q_{out} can sometimes be greater than the amount of runoff that can be used for hydropower generation. Therefore, another parameter, maximum runoff-hydropower capacity Q_{max} , is checked to determine if any portion of runoff release is spilled. The spill estimated in this step refers to the forced spill due to flood risk management. The minimum flow and spill, as well as the potential outage of turbines, are not simulated in the current model. The final monthly generation estimate G_{sim} is then determined.

$$\begin{cases} \text{If } Q_{out}(t) > Q_{max}, & Q_{out,hydro}(t) = Q_{max} \text{ and} \\ & Q_{out,spill}(t) = Q_{out}(t) - Q_{max} \\ \text{Otherwise,} & Q_{out,hydro}(t) = Q_{out}(t) \\ & Q_{out,spill}(t) = 0 \end{cases} \quad (2.8).$$

$$G_{sim}(t) = a * Q_{out,hydro}(t) \quad (2.9).$$

To estimate a in Eqs. (2.2) and (2.9), the total historic hydropower generation and total USGS WaterWatch runoff from 1980–2012 are calculated, and the parameter a is estimated by (total observed generation) / (total observed runoff). Other required parameters, including monthly watershed storage maximum $S_{max,Jan}, S_{max,Feb}, \dots, S_{max,Dec}$, storage minimum $S_{min,Jan}, S_{min,Feb}, \dots, S_{min,Dec}$, maximum runoff-hydropower capacity Q_{max} , and the initial runoff release and watershed storage conditions are calibrated by to minimizing the difference between observed and simulated monthly generation.

2.5.3 Hydropower Model Performance

To evaluate the applicability of WRES model, the first step is to examine the performance of monthly generation prediction equations (Eq. 2.1) used to estimate G_0 . The model parameters were estimated by 1980–2008 precipitation, runoff, and generation records and then validated by 2009–2012 observation. After estimating the regression parameters (Eq. 2.1) for each PMA study area and for each calendar month, the R^2 values of regression are summarized in Table 2.3. In most cases, the preselected five predictor variables may reasonably predict monthly generation (with R^2 greater than 0.7). However, for some particular months and for study areas with complicated water usage decisions such as the winter of WAPA-2, the R^2 values are low. While different predictor variables, alternative statistical models, or the actual operation rules may be used to improve the prediction of monthly generation, the regression equation remains unchanged for inter-regional consistency. It should be noted that G_0 only serves as an initial guess of monthly generation, and it will be corrected when the runoff storage is greater or less than the watershed limitations.

Table 2.3. R^2 of monthly generation prediction

	Winter			Spring			Summer			Fall		
	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
BPA-1	0.72	0.73	0.76	0.82	0.68	0.70	0.64	0.89	0.86	0.47	0.74	0.62
BPA-2	0.93	0.86	0.90	0.90	0.93	0.68	0.86	0.70	0.66	0.74	0.96	0.86
BPA-3	0.78	0.69	0.74	0.78	0.80	0.53	0.70	0.86	0.81	0.79	0.82	0.71
BPA-4	0.86	0.83	0.90	0.96	0.88	0.87	0.93	0.77	0.43	0.95	0.94	0.91
WAPA-1	0.92	0.93	0.92	0.85	0.57	0.89	0.91	0.87	0.90	0.92	0.95	0.94
WAPA-2	0.44	0.29	0.67	0.66	0.76	0.71	0.73	0.66	0.54	0.57	0.52	0.37
WAPA-3	0.94	0.95	0.90	0.88	0.89	0.92	0.88	0.93	0.96	0.92	0.88	0.95
WAPA-4	0.92	0.87	0.78	0.85	0.72	0.77	0.78	0.92	0.91	0.85	0.93	0.90
WAPA-5	0.85	0.75	0.58	0.81	0.72	0.61	0.49	0.54	0.84	0.77	0.74	0.38
WAPA-6	0.96	0.94	0.89	0.92	0.82	0.85	0.87	0.63	0.85	0.75	0.69	0.84
SWPA-1	0.85	0.91	0.78	0.87	0.89	0.89	0.81	0.84	0.84	0.69	0.85	0.89
SWPA-2	0.86	0.83	0.71	0.68	0.63	0.66	0.41	0.76	0.93	0.80	0.80	0.81
SWPA-3	0.83	0.85	0.83	0.81	0.73	0.66	0.59	0.71	0.72	0.84	0.70	0.67
SWPA-4	0.60	0.67	0.69	0.75	0.76	0.83	0.59	0.66	0.70	0.63	0.52	0.66
SEPA-1	0.95	0.86	0.95	0.94	0.92	0.92	0.95	0.91	0.92	0.98	0.89	0.91
SEPA-2	0.88	0.88	0.86	0.92	0.92	0.93	0.91	0.82	0.87	0.91	0.90	0.93
SEPA-3	0.93	0.86	0.90	0.83	0.87	0.95	0.74	0.89	0.81	0.91	0.79	0.90
SEPA-4	0.53	0.69	0.79	0.84	0.68	0.62	0.67	0.73	0.94	0.82	0.90	0.82

The WRES model performance was evaluated by comparing the simulated monthly generation time series to the observed series. The simulated WRES monthly generation and watershed storage of BPA-2 (Snake River) and SWPA-2 (Arkansas) study areas are illustrated in Fig. 2.13 and Fig. 2.14 as examples. In each figure, the simulated-versus-observed monthly hydropower generation is plotted in the upper panel, while the simulated watershed storage and maximum/minimum storage capability (dashed lines) are shown in the lower panel. To illustrate the importance of minimum and maximum watershed runoff storage capacity, a regression-only result that does not consider maximum/minimum watershed storage capacity is also shown (in

red) for comparison. Note that the hydropower plants in SWPA-2 are mostly run-of-river type and have a smaller total storage capability than BPA-2. Although the WRES watershed storage is a conceptual modeling variable (i.e., not the real storage of a particular facility), it represents the total storage in all reservoirs and retention facilities and hence may reflect the joint features of all storage facilities in the watershed.

In terms of monthly generation, both approaches can provide satisfactory results with high R^2 values. However, the underlying watershed runoff storage has a much larger difference. Using SWPA-2 as an example, the minimum and maximum runoff capacities provide a system limitation to store runoff so that the cumulative storage curve may look more reasonable (blue line versus red lines). Considering that all of the reservoirs in SWPA-2 have less than one year of storage, such system constraints must be considered. This feature is of particular importance for climate change studies since the distributions of future precipitation and watershed runoff could change significantly in some models. The watershed runoff information calculated by the WRES model will be able to help examine how the total watershed runoff may change under extreme climate conditions (under the current-day operation).

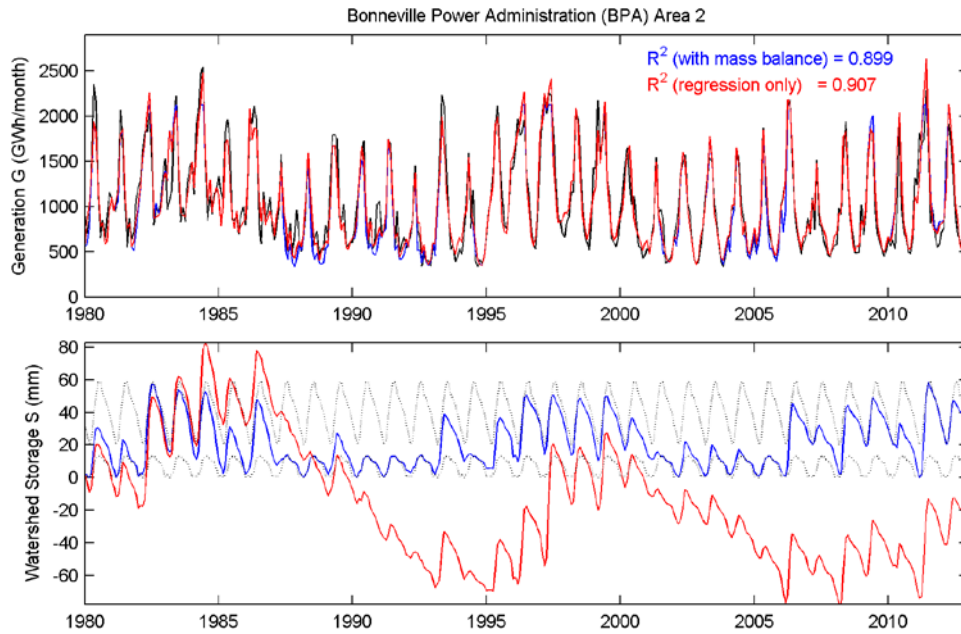


Fig. 2.13. Simulated monthly generation (upper panel) and watershed storage (lower panel) in BPA-2. The WRES outputs are shown in blue lines and observation in black lines. The maximum / minimum watershed storage is shown in dashed lines in the lower panel. A regression-only result without considering maximum / minimum watershed storage is shown in red for comparison.

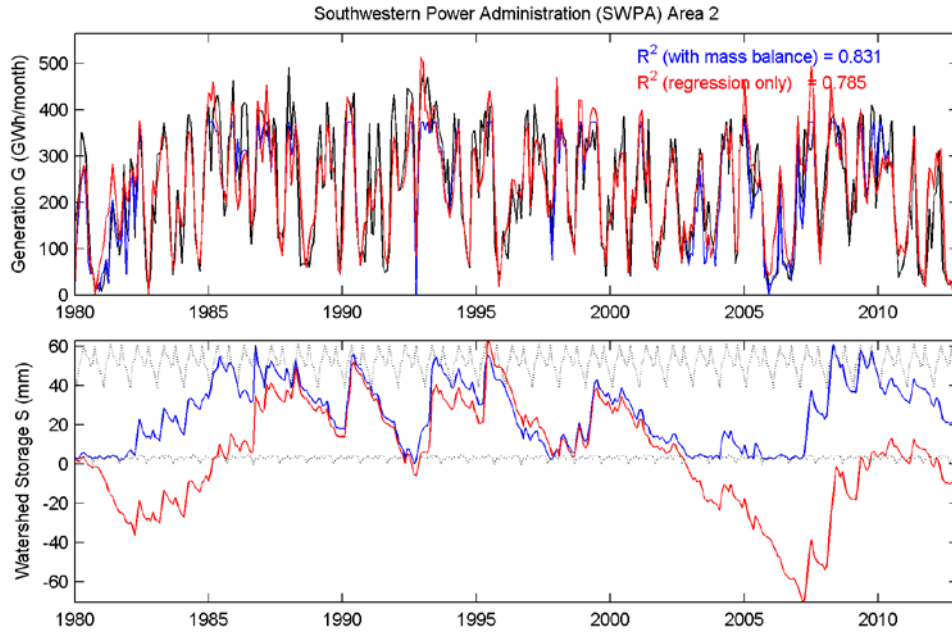


Fig. 2.14. Simulated monthly generation (upper panel) and watershed storage (lower panel) in SWPA-2. The WRES outputs are shown in blue lines and observation in black lines. The maximum / minimum watershed storage is shown in dashlines in the lower panel. A regression-only result without considering maximum / minimum watershed storage is shown in red for comparison.

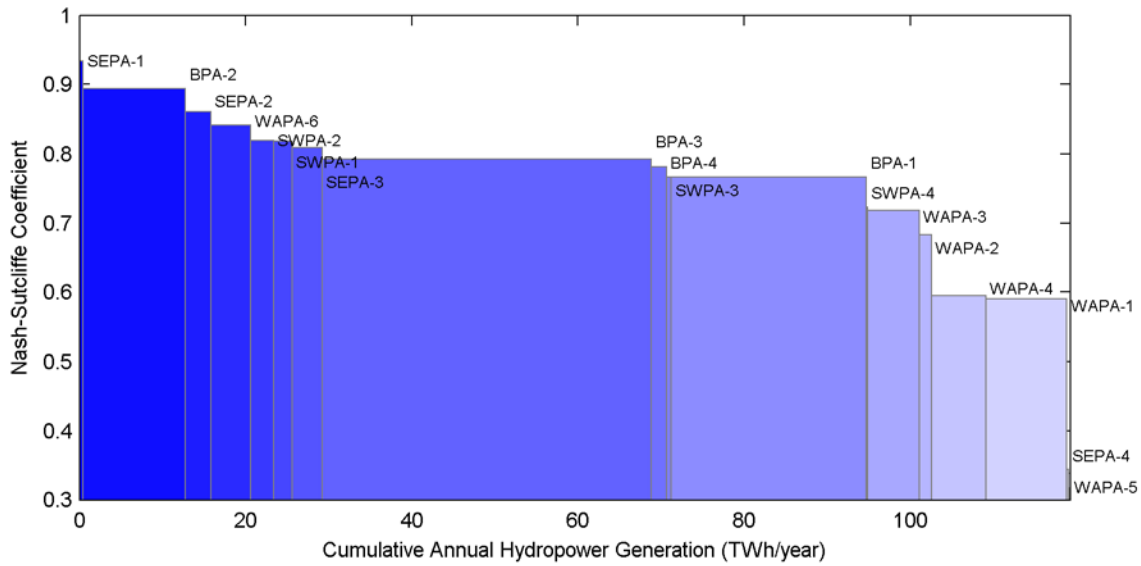


Fig. 2.15. The performance of WRES for the entire federal hydropower fleet

The performance of WRES for the entire federal hydropower fleet is further summarized in Fig. 2.15. To account for the different sizes of each PMA study area, the average annual hydropower generation is plotted on the x-axis. The commonly used Nash-Sutcliffe (NS) coefficient, which ranges from $-\infty$ (worst model efficiency) to 1 (perfect model efficiency), is used to evaluate the

performance of WRES. Evaluated by the NS between simulated versus observed monthly generation, the best performance was obtained in SEPA-1 (~0.94), followed by BPA-2 (~0.89) and SEPA-2 (~0.87), while the worst performance was found in SEPA-4 and WAPA-5 (~0.35). Overall, around 84% of annual federal hydropower generation was satisfactorily simulated by WRES with an NS coefficient greater than 0.7, and nearly 99% annual generation was simulated with an NS coefficient greater than 0.6. In addition, WRES can better simulate annual hydropower generation compared to the linear runoff regression method used in the first 9505 assessment (Sale et al. 2012). While further improvement will be required for areas such as WAPA-5, SEPA-4, WAPA-1, and WAPA-4, this current model should be able to provide a relatively accurate outlook of the entire federal hydropower generation on monthly and seasonal time scales.

2.5.4 Hydropower Model Limitations

While the WRES model may reasonably simulate monthly hydropower generation for a majority of federal hydropower systems, it is a lumped model with more restrictions than reservoir-based models. To avoid confusion with the conventional reservoir-based models, the WRES model limitations are summarized below:

- The WRES model is a generalized model mainly designed to simulate regional hydropower generation (and the corresponding watershed storage variation) of various federal hydropower study areas with minimum meteorological and hydrological inputs. Most of the reservoir-specific aspects such as operational constraints, competing water demand, flood risk management, ecosystem services, and reservoir sedimentation cannot be addressed in WRES.
- While the WRES model does not require reservoir parameters, it requires complete, long-term, accurate observation of precipitation, runoff, and generation. For areas with insufficient and less accurate precipitation and runoff records (e.g., WAPA-5), the WRES model performance is poor.
- In the current WRES model application, multivariate regression is used to generate an initial guess of monthly generation prediction under the implicit assumption that this statistical relationship will not change significantly in the future hydro-climate conditions. This modeling component can be further improved in the future assessment to include more non-statistical operational conditions.
- While a conceptual watershed runoff storage variable is introduced in WRES, it should not be confused with the actual reservoir storage in the study area. Nevertheless, the watershed runoff storage variable does show correlation to the overall wetness/dryness in the system. Taking SWPA-2 as an example, both hydropower generation and watershed runoff storage are at minimum during the 2006 drought.
- While it is assumed that the monthly runoff and generation can be converted through a simplified relationship (Eq. 2.6), based on our previous experience (Sale et al. 2012), such a relationship can be more complicated at finer temporal resolution. In reality, hydropower is jointly controlled by both head and flow, so the linear relationship will only hold at coarser

temporal scales and/or when the head variation is small (i.e., run-of-river hydropower plants). This simplified relationship should be further examined in a subsequent assessment.

- Given that the reservoir operation cannot be adjusted in the WRES model, the future hydropower and runoff storage projections made by WRES correspond to the current-day operation. The system should be able to accommodate further flexibilities to extreme climate conditions with further adjustment to the reservoir operation. This operational flexibility can only be examined through site-specific models and is not examined in this study.

2.6 Power Marketing Systems

A description of what PMAs are and what they do was provided in Section 1.2.2. Climate change will not only alter the amount and timing of generation at federal hydropower facilities—the PMA’s hydropower supply curve—but also its customers’ electricity demand profile.² The relative strength of supply and demand effects along with climate-related impacts on the availability and efficiency of other electricity generation and transmission assets will determine if and how the competitiveness and value of federal hydropower will be affected by climate change.

The sections on power marketing discuss the channels through which climate change might impact the products and rates that PMAs offer to their customers. A central message is that climate change is only one among the many sources of hydropower generation variability that PMAs must manage in order to collect adequate revenue that will enable them to make their annual Treasury payments. Other sources of variability are the water demands arising from competing water uses, operational changes to meet environmental compliance objectives, integration of variable renewables into the power grid, and aging equipment. Understanding the interactions among the various sources of variability is crucial to managing them effectively.

The power marketing sections also describe the ways in which the PMAs manage the costs brought about by these sources of variability. PMA’s contracts and rates generally include flexibility mechanisms to accommodate generation variability. An important part of the PMA’s response to imbalances between supply and demand caused by climate change or other reasons involves transactions with the wholesale electricity markets. For that reason, a brief description of the regional market context is included in each of the following sections. In addition, all PMAs except Southeastern are registered with NERC as balancing authorities and, as such, they must balance generation and load³ within their control areas. As the percentage of variable renewables in their control areas increases, federal hydropower capacity is also being used for balancing their fluctuations, to the extent allowed by the authorized purposes of each project.

Mechanisms through which climate change impacts PMA’s supply and demand

Climate change most directly affects PMAs by altering the volume and timing of runoff available at each of the federal projects whose power they market. How much of the runoff will be used for electricity generation also depends on the competing uses of water stored at each project’s reservoirs. Water demands for those competing uses can also be affected by climate change.

² Scott and Huang (2007) provide a summary of the projected effects of climate change on energy use in the United States.

³ In this document, the terms “load” and “demand” are used interchangeably when referring to electricity consumption.

Consumptive uses of water (e.g., irrigation and municipal water supply) can reduce available water for hydropower production. Recreation, navigation, flood control, and fish operations all impose constraints on reservoir elevation that affect the timing and flexibility of hydropower operations and, ultimately, the price at which the PMAs will sell federal hydropower. The simulated generation futures in this report take into account the water dedicated to competing uses.

Although Bonneville is the only PMA responsible for serving its customers' load growth (if they request it), all four PMAs have an interest in understanding climate-related changes in their customer demand profiles. For instance, if climate change results in a year-round temperature increase, residential demand—which makes up a large fraction of the load of municipalities and other public bodies served by PMAs—will decrease in winter and increase in summer. Thus, the time of year—or time of day—when electricity is most valuable to the preference customers served by PMAs will likely be modified by climate change. To the extent possible, the PMAs try to schedule generation at those times in which it is most valuable to its customers. Their ability to do so could increase or decrease depending on the combined effects of changes in generation timing and changes in seasonal and daily demand profiles.

A quantitative assessment of temperature-induced demand effects would require detailed information on load characteristics. Auffhammer and Mansur (2014) and De Cian et al. (2007) reviewed the statistical techniques used to estimate the relationship between temperature and electricity demand. It should also be noted that potential temperature-induced increases in the PMA's customers' load can be offset through implementation of energy efficiency and demand response programs or the use of behind-the-meter generation (e.g., distributed solar). The potential for climate-related changes in the load profile of PMA's customers is only discussed qualitatively in this report but a more detailed analysis will be proposed as future work.

PMAs manage generation variability through their contracts and rates

A review of the power allocation and rate setting practices used by each PMA to market federal hydropower reveals a significant degree of flexibility when adjusting to changes in water availability.

- Although there are variations across hydropower projects, preference typically sign longer-term (15 to 50 years) contracts, and the contracts may include take-or-pay provisions meaning that the preference customers pay for the power allocation and/or the associated energy, even if they decide they don't want to receive the corresponding energy from the PMA. Take-or-pay contract provisions help protect the PMAs from demand destruction if wholesale prices become more attractive than those of federal hydropower during the contract term.
- Contracts have been structured such that those hydropower projects with the most hydrological uncertainty are marketed as peaking power or "as available" energy (i.e., not offering customers a guarantee of continued availability). Customers receiving power from those projects may need to procure the remaining required generation through other means at prices that could far exceed the price they pay via the long-term contract with the PMA.

- PMAs use conservative estimates of availability—based on historical dry years—for their contractual power allocations to customers. When power beyond what is needed to fulfill the contract requirements is available, the PMAs offer it to their customers and/or on the wholesale market.
- PMAs can adjust rates at annual or even higher frequencies to recover the costs associated with drought and fulfill their Treasury payments.

Through project-specific contract structures and flexibility to adjust rates, the PMAs maximize the probability of being able to make their planned payments to Treasury each year. The bottom line is that financial risk associated with federal hydropower variability is ultimately passed through to the PMA customers. Accepting the bulk of the risk in these contracts has historically made sense for customers because, most of the time, the rates offered by the PMAs have been substantially cheaper than the available alternatives (GAO, 2000). At the end of their long-term contracts, customers can re-evaluate if the conditions offered by the PMAs continue to be appealing in the face of changes in climate as well as other electric market developments.

Interactions between PMAs and wholesale electricity markets

Changes in quantity or timing of water available for hydropower generation affect the quantity (in MWh) the PMAs have to purchase from/sell to the wholesale market in order to balance supply and demand. Fig. 2.16 shows PMA wholesale purchases as percentage of total PMA sales from 2001–2013. Pronounced peaks correspond to drought years (e.g. 2006 and 2012 for Southwestern, 2008 and 2012 for Southeastern). However, purchases by PMAs on the wholesale market are not necessarily a result of drought. They might be needed, for instance, to replace energy not produced due to 1) plant outages, 2) operational restrictions associated to fish protection or 3) some hydropower units being used to balance fluctuations from variable renewables rather than dispatched for generation.

Stresses on electricity generation, transmission, and distribution infrastructure from increased temperatures or decreased water availability will extend beyond federal hydropower production. DOE (2013) offers a comprehensive account of potential impacts which include reduced efficiency of cooling—and even partial shutdowns to avoid reaching water temperature thresholds that would be dangerous for fish populations—at thermoelectric generation facilities and reduced efficiency of electricity transmission at high temperatures. Thus, during a dry summer, limited hydropower production could be compounded by these other effects, resulting in very high prices at times in which the PMAs might need to purchase replacement power from the wholesale market.

Another informative metric describing the relationship between PMAs and the wholesale electricity markets is the correlation between the monthly average wholesale market price and the monthly total generation at federal projects with the respective PMA. The fraction that hydropower represents in the generation portfolio of a given region and the mode of operation of the hydropower plants both have a role in determining the sign and magnitude of the correlation. All else being equal, periods with higher hydropower availability result in lower wholesale market prices (EIA 2012). According to this statement, the correlation between PMA generation and price should be negative. On the other hand, the more flexibility a hydropower plant has to

follow price signals, the stronger the positive correlation between generation and prices should be. A correlation analysis was performed using monthly generation data and monthly average prices to examine the relationship between those two variables.

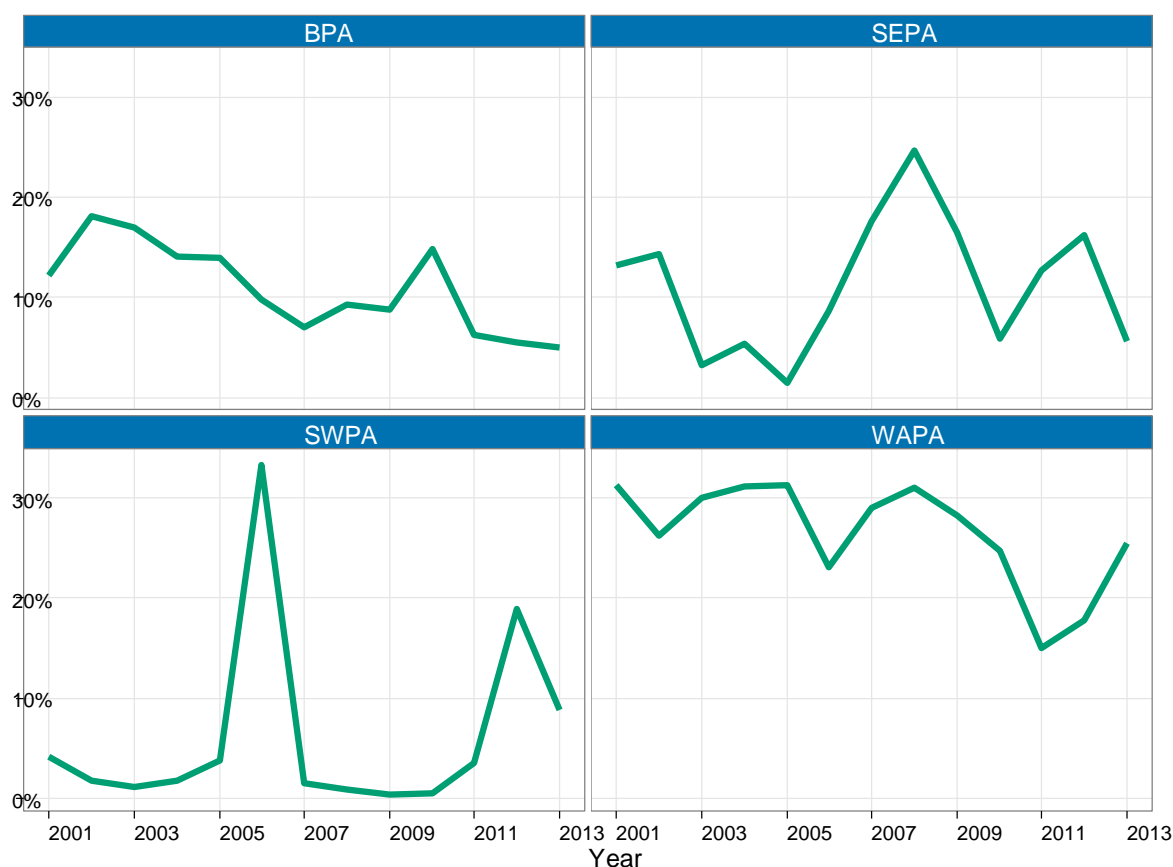


Fig. 2.16. PMA wholesale power purchases as a percentage of total PMA sales (2001–2013) (EIA Form 861).

Due to the large percentage hydropower generation represents within the total generation portfolio within BPA’s region of operation, the (negative) correlation between BPA’s generation and the regional wholesale market price could hypothetically be stronger, i.e., closer to -1, in comparison to the other PMAs. Table 2.4 confirms that the strongest negative correlation corresponds to the pair of Bonneville’s generation and Mid-Columbia wholesale price. Conversely, a strong, positive correlation could hypothetically arise if federal hydropower production is able to closely follow market price signals. In most cases, the volume and timing of generation at the federal projects is largely determined by the excess water available after other priorities (e.g., flood control, irrigation, recreation, or fish operations) have been fulfilled and not a price signal. Southwestern, which markets its power as peaking power, is the only one displaying a positive correlation between generation and price.

An electricity market trend that is impacting both wholesale price levels and federal hydropower operations is the increased penetration of variable renewables—wind and solar— particularly in the Western half of the U.S. (Chang et al. 2013, Fischer 2010, Sensfuss et al. 2008). Operating

reserves requirements increase as renewable penetration grows (Holttinen et al. 2013).⁴ Hydropower provides some of those additional reserves in the control areas managed by the PMAs. Technically, hydropower is well suited to serve this function because it can quickly ramp up and down as needed. However, for the federal multipurpose projects, providing this type of services engenders allocation challenges (Fernandez et al. 2013, Bélanger and Gagnon 2002).

Table 2.4. Correlation between PMA monthly generation and average monthly wholesale price

PMA-wholesale price pair	Time period	Correlation	p-value
Bonneville-Mid Columbia on-peak	2008-2012	-0.391	0.0020
Western-Palo Verde on-peak	2008-2012	-0.077	0.5579
Western-NP15 on-peak	2009-2012	-0.284	0.0589
Southwestern-SWPP SPA Hub	2008-2012	0.547	0.00001
Southeastern- SOCO (marginal cost)	2008-2012	-0.270	0.0369
Southeastern- TVA (marginal cost)	2008-2012	-0.223	0.0870

Notes: The Mid-Columbia, Palo Verde, and NP-15 on-peak prices were obtained from EIA Wholesale Electricity Market Data. The Southwestern Power Administration (SPA) hub price was obtained from the Southwestern Power Pool website. The Southern Company (SOCO) and TVA series are the system lambdas from FERC Form 714 at each of those two balancing authorities. System lambda is “the incremental cost of energy of the marginal unit assuming no system constraints.” It is used only in those regions that don’t have an independent system operator or regional transmission organizations (RTOs) in its footprint.

An opportunity cost arises for PMAs when they allocate capacity (MW) to provide reserves as opposed to that capacity being allocated for energy services (MWh) that can be sold to customers at the specified rates or, if its surplus power, at the market price. If hydropower units are used as reserves during peak load hours in which generation is particularly valuable to PMA customers, the result will be a less attractive shape for the energy received and/or an increase in rates. Additionally, during periods in which electricity generated by wind and solar is available at a lower price, PMA’s customers may prefer not to receive more expensive generation from federal hydropower. This dynamic might lead to situations in which excess power is not allocated, meaning water is spilled and does not pass through the turbine for electricity generation purposes.

One way in which PMAs are coping with these financial trade-offs (opportunity cost) and operational decisions (capacity allocation) is by considering the possibility of becoming members or more closely affiliated with larger regional transmission organizations (RTOs) or energy imbalance markets (EIMs). Renewables integration studies find that cooperation among balancing areas and sub-hourly scheduling are essential to mitigate variability both in generation and in load and to reduce the overall costs of achieving high penetrations of variable renewables (King et al. 2011, GE Energy 2010). Joining larger balancing areas may result in the dynamic where costs of integrating renewables are shared among all participants, though cost may not be equally allocated, and the PMA may have improved mechanisms for maintaining grid reliability

⁴ Operating reserves is “the active power capacity that can be deployed within a given operating timeframe to assist in generation and load balance and frequency control.”

while providing energy when it is most valuable for their customers.⁵ In addition, RTOs typically have co-optimized energy and operating reserves markets that take into account the opportunity costs of each generation unit. However, there are also costs associated with joining the RTOs/EIMs (e.g., administrative charges, staffing and equipment to interface with the market operator) so that the attractiveness of this option varies case by case.⁶

The topics identified here are developed in more detail for each of the PMAs in the power marketing sections of the report. Sections 3.2.2, 4.3.2, 5.3.2, and 6.3.2 provide a broader context in which to interpret the impacts of simulated temperature, precipitation, and generation changes on the business model of PMAs, the relationship with their customers, and with the electricity markets.

2.7 Indirect Effects

In addition to the quantitative assessment described in this section, climate change can also affect competing water demands and environmental requirements that may indirectly constrain future hydropower operations (also known as indirect effects). Some of these issues were identified and discussed among PMAs, Reclamation, USACE, USGS, and other agencies during a preparation workshop for the second 9505 assessment that was hosted by ORNL in September 2014. These issues include:

- **Competing Water Demand**

Competing water demand refers to the amount of water withdrawn or released from reservoirs that does not contribute to hydropower generation (e.g., water supply for irrigation, municipalities, and industries). Since hydropower is only one of the many authorized purposes from federal dams (Martínez et al 2015), change in the volume and timing of water allocated for these various demands can have an impact on future hydropower generation. Some recent studies have suggested that climate change effects on competing water demands may reduce the available water for hydropower generation (Raymondi et al. 2013), and climate warming will likely increase irrigation demands over a longer growing season (Brown et al. 2013). The ways that existing water rights may affect competing water demand is another factor of consideration.

- **Environmental Requirements**

Environmental requirements refer to the operational constraints (e.g., see Reidy Liermann et al. 2012) that hydropower facilities are required to meet for aquatic ecology protection purposes, such as maximum instream temperature and minimum streamflow releases. Long-term historical data for unregulated gauges in the Pacific Northwest has shown increasing trends in instream temperature that tracked increasing trends in air temperature (Isaak et al. 2012). A number of simulation studies in the Pacific Northwest also suggest that stresses among required instream flows, flood control, and generation will increase as the climate warms (Lanini et al. 2014, Lee et al. 2009, Mote et al. 2003, Miles et al. 2000). Payne et al. (2004) projected an increased competition between water allocated for hydropower

⁵ Since PMAs would pass through the costs associated with participating in a larger balancing area to their transmission customers, cost allocation mechanisms based on a “beneficiary pays” principle will be needed for those customers to support joining the larger balancing area.

⁶ <https://www.ferc.gov/industries/electric/indus-act/rto/spp/spp-entergy-cba-report.pdf>

generation and instream flow requirements, and suggested that the water storage might not be available for flow augmentation to meet instream flow targets in summer. Nevertheless, most current research has assumed “business as usual operations”, while in reality water and resource managers may have flexibility to adjust operations to help meet requirements. Such issues have not been fully explored.

Although both competing water usage and environmental requirements are familiar challenges for water and energy managers, how these challenges may evolve under projected future climate conditions is not well understood. Intuitively, increasing air temperature may have an influence on competing water demand and instream temperature, but quantification of such effects on future hydropower operation is currently an open scientific question. The existing tools, data, analyses, and even concepts that were developed for local operational purposes may not be directly applicable to support planning and decision making efforts focused on addressing potential risks from climate change. In addition, these indirect effect issues are mostly site-specific, and would require a detailed reservoir-based model that includes site-specific operational rules, water demand, inflow, outflow, and temperature measurements to simulate the effects of climate change. Obtaining these data and developing such a model for comprehensive indirect effects assessment will require substantial effort and resources.

Given the important implications of these challenges, the need to further explore and examine how climate change may indirectly impact future hydropower operations is recognized. Following the workshop in September 2014, efforts were initiated to identify a methodology to quantitatively evaluate the potential climate change risks associated with indirect effects. These efforts were targeted towards increased understanding of four main challenges in the indirect effects analysis: (1) simulation of instream temperature in unregulated stream-reaches, (2) projection of future water demand, (3) simulation of reservoir releases and water temperature, and (4) development of a probabilistic risk assessment framework incorporating indirect effects. The frontier of research in each of these challenge areas (not quantitatively addressed in this study) is discussed below:

- **Simulation of Instream Temperature in Unregulated Stream-reaches**

To model the streamflow and instream temperature at unregulated stream-reaches, one approach is to perform further simulation to convert the grid-based runoff projections into routed flow and temperature. Given the usage of VIC hydrologic model in this study, one direct extension can be the VIC-River Basin Model (RBM) model (Yearsley 2009, 2012). RBM is a one-dimensional instream temperature model that solves the time-dependent equations for the transfer of thermal energy across the air-water interface. The model has been modified to make use of the VIC output, and was utilized to analyze the vulnerability of US and European electricity supply to climate change (Van Vliet et al. 2012, Nartos and Chester 2015). Since many of the VIC-RBM inputs have been prepared for the VIC routing model (Lohmann et al. 1998), the required model implementation efforts are reduced. Nevertheless, to improve the model performance, computationally intensive calibration is still required that cannot be completed before the conclusion of the second 9505 assessment. Additional efforts will be needed to improve the calibration of default RBM parameters for site-specific application at federal reservoirs.

- **Projection of Future Water Demand**

Based on the USGS water use data from 1960–2005, a method was developed by Brown et al. (2013) to project future water use from the trends in water use efficiency and major drivers of water use. The study suggests that the climate-based increase in the projected water use is attributable mainly to increases in agricultural and landscape irrigation in response to rising potential evapotranspiration due to climate change. Applying the method developed by Brown et al. (2013), scenarios of future water demand can be developed for watersheds contributing to the federal hydropower reservoirs. These scenarios can then be used to alter water available for reservoir and hydropower simulation to test the sensitivity of projected future hydropower generation due to change of future water demand. A recent study led by the Reclamation West-Wide Climate Risk Assessments (Huntington et al. 2015) also laid out a generalized method to estimate potential changes in crop irrigation demand in eight major river basins in the western United States.

- **Simulation of Reservoir Releases and Water Temperature**

Simulation of reservoir releases, water temperature of those releases, and the evolution of water temperature downstream requires modeling of systemic reservoir operations and the thermal hydraulics of river and reservoir segments. While the simulation of series and parallel reservoir operations and the localized simulation of water temperature are each mature areas of water resources engineering practice, coupling of water temperature as a function of reservoir releases and integration of such dynamic dependence into reservoir operations modeling is a nascent area of water resource research (Shaw et al. 2015). To explicitly evaluate how the change of future meteorological and hydrological conditions may affect reservoir operation to meet downstream water quality targets, one approach is to couple a reservoir systems operation model such as RiverWare (Zagona et al. 2001) or HEC-ResSim (Klipsch and Hurst 2013) with a detailed reservoir hydrothermal dynamics model such as CE-QUAL-W2 (<http://www.ce.pdx.edu/w2/>) suggested by the USGS staff (Buccola et al. 2012). The RiverWare or HEC-ResSim models implements multi-reservoir water balances and myriad prioritized rules and constraints on reservoir elevations and releases for several US river systems. The CE-QUAL-W2 model can simulate flow, stage, velocity, water temperature, oxygen, pH, nutrients, organic matter, algae, aquatic plants, and has been applied for many US federal reservoirs. However, the coupling of these two kinds of modeling capabilities, for either short-term or long-term simulation, is a non-trivial developmental effort currently underway (Shaw et al. 2015). Furthermore, such coupled simulations were not feasible within the scope of this study. Further discussion with resources managers will be required to identify an appropriate scope and a suitable subset of reservoirs for a case study.

- **Development of a Probabilistic Risk Assessment Framework**

In order to objectively interpret the projected risks associated with indirect effects, a probabilistic climate change vulnerability assessment (CCVA) framework can be tested. The CCVA is a form of risk assessment often used to evaluate the impacts of climate stress on specific endpoints valued by society (El-Zein and Tonmoy 2015, Gaichas et al. 2014, Higgins and Steinbuck 2014). The value of a risk-assessment framework is its ability to present probabilistic summaries of whether the projected future changes may exceed the

targeted thresholds under future climate conditions. Tools borrowed from risk assessment provide a quantitative approach to evaluate vulnerability to climate change for environmental thresholds (Landis et al. 2013). Using an equilibrium river temperature model (Bogan et al. 2003) and natural VIC streamflow as surrogates, a proof-of-concept experiment was conducted to demonstrate the applicability of CCVA. This initial framework will undergo further in-depth scientific review for confirmation and verification.

Overall, while potential approaches have been identified and tested for the indirect effect assessment, it is recognized that one main challenge is associated with the modeling uncertainty. In order to make the models useful for decision making and risk assessment, additional efforts on model adjustment and calibration will be required. However, given the time and resource constraints, such labor and computational intensive effort (for all federal hydropower reservoirs) cannot be completed before the conclusion of the second 9505 assessment. Additional details regarding these efforts to evaluate indirect effects using existing tools and methodologies are planned for review and publication in separate documents to support future efforts to advance scientific understanding in this area.

3 THE BONNEVILLE REGION

Using the methodology described in Section 2, the results for federal hydropower plants marketed through the Bonneville Power Administration (BPA or Bonneville) are summarized in this section. Descriptions of the study area, background on hydropower operations, and marketing characteristics for Bonneville are described in the first subsection. Section 3.2 discusses the hydroclimate projections and a review of other recent studies within Bonneville's operating territory. The potential impacts on federal hydropower generation and risks to federal hydropower marketing at Bonneville facilities are discussed in Section 3.3.

3.1 Regional Characteristics

3.1.1 Study Areas

Bonneville is the largest PMA in the US in terms of its total installed capacity (20,583 MW), and its average annual generation (75.7 TWh/year) (NHAAP 2014). All federal hydropower projects in the Bonneville region are managed as a single Federal Columbia River Power System (FCRPS). 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 mi² in Canada. Bonneville is subdivided into four study areas based on power system and watershed boundaries (Fig. 3.1):

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

The first Bonneville study area, BPA-1, is the Upper Columbia River system. This river system includes the main stem of the Columbia River and its above tributaries, including Grand Coulee Dam. The total drainage area of BPA-1 is 75,058 mi², with forty-five percent of this area located in Canada. The major tributaries where federal hydropower plants are located are the Pend Oreille and Kootenai River basins. The watershed of this uppermost area is predominantly mountainous, with a median elevation of 4,600 ft. and maximum elevations exceeding 11,000 ft. in the Canadian Rockies. The dominant land cover is evergreen (69%) and deciduous (13%), needle leaf forest with minor amounts of grasslands and mixed forests (6% each). Water management in this study area is mainly controlled by international treaty, with a smaller portion controlled by US projects on the Pend Oreille, Kootenai, and Flathead to Pend Oreille, Kootenai, and Spokane.

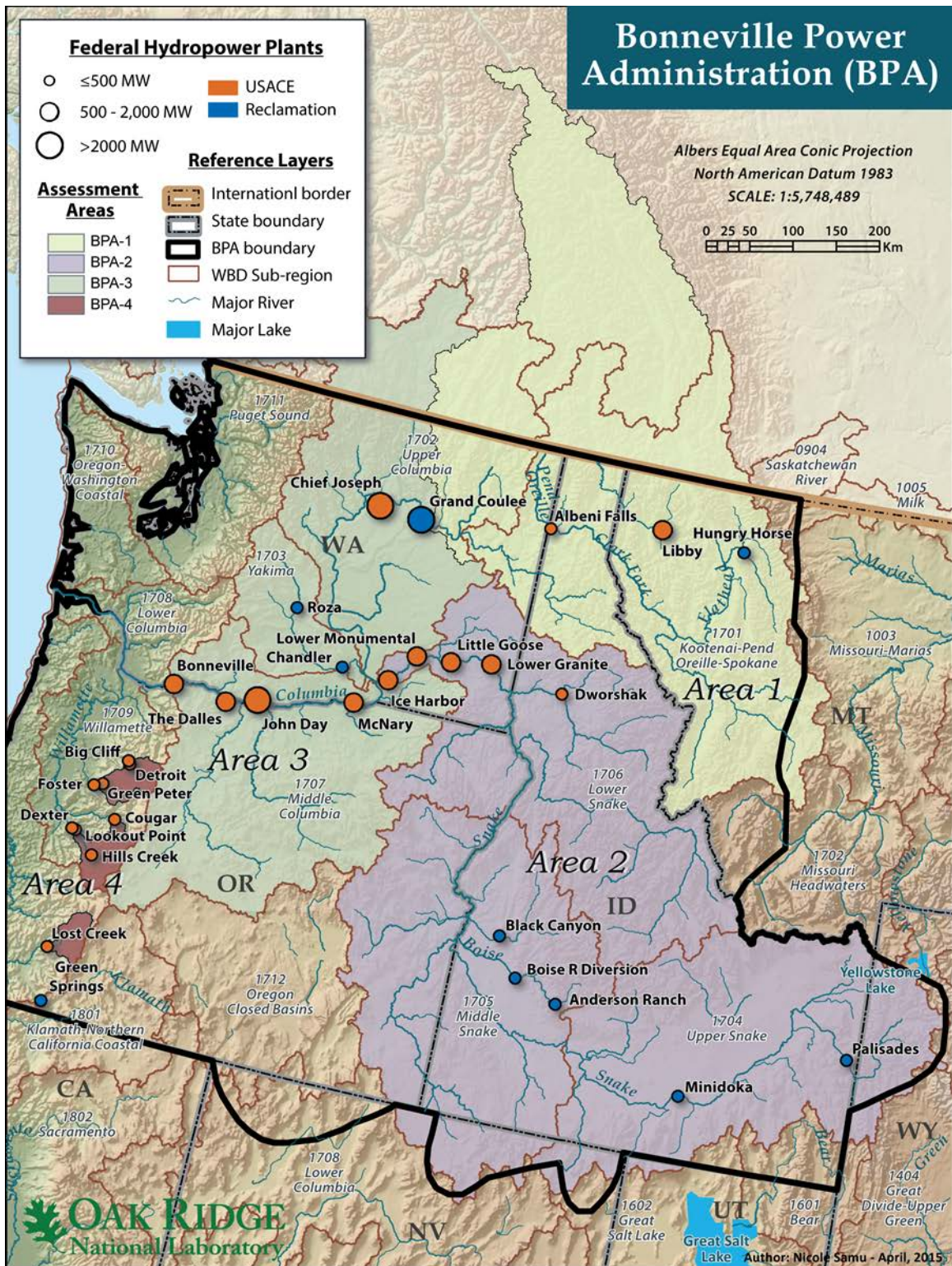


Fig. 3.1. Map of the federal hydropower plants and study areas BPA 1-4 in the Bonneville region.

The second study area, BPA-2, is the Snake River Basin, upstream of the Columbia–Snake confluence. The total drainage area of BPA-2 is approximately 108,000 mi², 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 Payette Rivers. Topography here is a mix of high plains and mountains, with a median elevation of 5,112 ft. and a maximum of over 12,000 ft. BPA-2 is a semi-arid area with relatively diverse land cover, including 52% grassland, 27% evergreen forest, 12% cropland, and 9% closed scrubland.

The third study area, 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 total drainage area of BPA-3 is 242,199 mi² (including the two upstream areas, BPA-1 and BPA-2). 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., and the highest elevations are upstream in other areas (BPA-1 and BPA-2). BPA-3 is also a semi-arid area. Land cover in BPA-3 is 52% closed scrubland, 38% grasslands, 14% cropland, and 7% woody savanna.

The fourth study area, 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., and the maximum elevation in this part of the Cascade Range is 9,459 ft. Land cover is 94% evergreen needle leaf forest.

3.1.2 Federal Hydropower in the Bonneville Region

The Columbia River Basin is rich in water resources, representing the most heavily developed region for hydropower in the US. 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 (NHAAP 2014). The federal hydropower plants in the region are owned and operated by either USACE or Reclamation (Table 3.1). Some of the largest federal hydropower plants in the US are located on the Columbia River. For example, Reclamation's Grand Coulee Dam is the largest federal hydropower plant in the US, with an installed conventional capacity of 6,495 MW, and another 314 MW of pumped-storage capacity. The largest USACE hydropower plant is the 2,456 MW Chief Joseph Project, which is immediately downstream of Grand Coulee. A complete list of federal hydropower plants in the Bonneville region is located in Appendix B.

Aging infrastructure and rising costs for O&M are serious concerns for Bonneville (Sale 2011). The federal hydropower plants in the Bonneville region are on average 52 years old (NHAAP 2014). The oldest USACE project within this region is Bonneville Dam, which began operating in 1938, and the last USACE project constructed was Lost Creek in 1977. Reclamation's hydropower plants in this region were constructed between 1909 (Minidoka) and 1964 (Green Springs). The heavy O&M cost may reduce Bonneville's abilities on balancing other emerging issues, such as integrating large volumes of variable renewable generation.

Almost all hydropower plants in the Bonneville region are part of multipurpose water developments where hydropower represents one of many services a reservoir must provide. Balancing the operating and policy complexities of providing multiple services (flood control, navigation, irrigation, fish and wildlife protection, and municipal and industrial uses) remains a key objective for the federal dams in the Bonneville region. Bonneville, USACE, and Reclamation maintain a River Management Joint Operations Committee (RMJOC) tasked with long-term planning and operational decisions that affect the Columbia and Snake River Basins.

Some management decisions in this area are subject to international considerations in the use of the Columbia River. Around 35% of the total runoff (as measured at The Dalles Dam) flowing through the Columbia River originates in Canadian watersheds; therefore, the basin is managed as an international resource. The Columbia River Treaty coordination between Canada and US on power and flood control provides \$100's million dollars of annual mutual benefits across the Columbia River Basin (USACE and BPA 2009). Further details on multipurpose water management issues in the Bonneville region can be found in Sale et al. (2012).

Table 3.1. Summary of federal hydropower plants in the Bonneville region

Area	Area name	Number of plants			Total installed capacity ^a (MW)	Average annual generation ^b (GWh/year)
		USACE	Reclamation	Total		
BPA-1	Upper Columbia	2	2	4	7,804	22,426.5
BPA-2	SNAKE RIVER	5	5	10	3,691	11,997.0
BPA-3	Mid-Lower Columbia	5	2	7	8,613	39,513.1
BPA-4	Cascade Mountains	9	1	10	475	1,793.5
Totals		21	10	31	20,583	75,730.1

^a EIA 2013 total nameplate capacity. Includes both conventional hydro and pumped-storage.

^b EIA and BPA average annual generation from 1970 to 2012, conventional hydro only.

3.1.3 Power Marketing by Bonneville

Bonneville is a PMA—established by the enactment of the Bonneville Project Act of 1937—that markets the energy produced by federal hydroelectric plants located on the Columbia River and its tributaries. A general description of a PMA and how it conducts its mission is presented in Section 1.2.2. Subsequent legislation has resulted in additional obligations for Bonneville. In 1980, the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) required Bonneville to provide its customers enough megawatt-hours to cover their growing electricity demand rather than just providing the available capacity and energy from the FCRPS projects. In order to fulfill its responsibility for load growth, Bonneville makes augmentation purchases to complement the output from the federal hydropower system. In addition, the Northwest Power Act directed Bonneville to pay for fish and wildlife programs, establish energy efficiency programs, promote renewable energy development in its region of operation, and extend some of the benefits of federal hydropower to residential and small farm customers served by IOUs (through the so-called Residential Exchange Program).

Bonneville received authorization, in the Transmission System Act of 1974, to borrow money directly from the US Treasury. Bonneville's borrowing authorization was increased by the Northwest Power Act of 1980 to meet certain obligations under that Act. Since then, Bonneville's borrowing limits have been expanded several times. The most recent expansion limit took place in 2009, an additional \$3.25 billion authorized in support of transmission infrastructure investment needs. Moreover, since 1974, BPA is a self-financing agency that can use the revenues from selling power and transmission services to cover O&M expenses as well as an extensive fish and wildlife program. Later, the Energy Policy Act of 1992 allowed Bonneville's power sales revenues to also be used for directly financing capital upgrades at the FCRPS hydropower facilities (NRC 2013). Borrowing authority, self-financing status, and authorization to use sales revenues to directly fund capital upgrades are all unavailable to the other three PMAs, which continue to depend heavily on annual appropriations.⁷

Bonneville markets power from 31 federal hydropower projects which make up the FCRPS. In addition to the hydropower projects, it also markets the power from a nuclear plant (1,075 average MW of firm power) and has signed multiple power purchase agreements to acquire output from renewable energy projects in the region (448 average MW of firm power). Bonneville also owns and manages 15,156 miles of high-voltage transmission lines—about three-fourths of the high-voltage transmission in its service territory—and has 490 transmission customers.

Bonneville has long-term contracts with 142 customers. In accordance with the original mission of the PMAs, most of Bonneville's customers fall into the category of preference customers. The 134 preference customers include 54 cooperatives, 42 municipalities, 28 public utility districts, 7 federal agencies, 2 tribal utilities, and 1 port district.⁸ Bonneville also has long-term power contracts with six IOUs and two direct service industrial (DSI) customers (one aluminum smelter and a paper mill).

Bonneville interacts with the surrounding regional electricity markets in two ways. First, it acts as a power marketing authority that purchases capacity and energy from other resources outside the FCRPS plants to fulfill its contractual obligations with customers. These purchases (replacement power purchases) involve a portfolio of transactions ranging from long-term power purchase agreements to spot purchases for next-day delivery. On the other hand, whenever available generation from the FCRPS is more than needed to satisfy its customers' load, Bonneville sells the surplus in the wholesale market (surplus power sales). Second, Bonneville is also registered with the North American Electric Reliability Corporation (NERC) as a balancing authority. This means it is responsible for compliance with all NERC requirements regarding grid reliability within its control area, and it must balance generation and demand for all generation resources and customers in that footprint.

To redefine its power marketing strategy, in 2005, Bonneville initiated a discussion process called the Regional Dialogue with its customers and other stakeholders in the region. Until then, Bonneville had combined the costs of FCRPS generation and secondary power purchased to satisfy its customers' contracted amounts into a single rate. During the late 1990s, this rate

⁷ Western received borrowing authority in 2009 to finance investments in transmission infrastructure.

⁸ Bonneville must provide access to federal hydropower to new entities that would fall under the preference customers category. In the last round of power contract negotiations, 250 MW of capacity were earmarked for "new publics."

structure resulted in Bonneville's rates being greater than wholesale market rates. The new rate structure that resulted from the Regional Dialogue and that has been applied since 2012 follows a tiered methodology. The lower cost Tier 1 rates only apply to the sales of firm power available from the FCRPS to preference customers. Tier 2 rates will reflect the cost that BPA pays for purchasing power for other sources to fill the gap between available firm FCRPS power and total contracted loads with their customers. This tiered approach provides better price signals to the customers who can choose sources other than Bonneville to purchase additional power if it is less expensive and/or better matched to their daily and seasonal demand patterns than that offered through Tier 2 rates (BPA 2007).

In FY12, the total firm FCRPS power allocated across Tier 1 rate customers was 7,100 MW. The portion of the firm power accessible by each customer is called the *contract high water mark (CHWM)*. The CHWM is updated during each rate case (i.e., every two years) to account for changes in the forecasted firm output of the FCRPS.

The new long-term contracts apply to the FY12–FY28 period.⁹ Bonneville's preference customers have three product choices when negotiating their long-term contracts:

- **Load Following:** Bonneville serves the customer's net requirements (i.e., the difference between the customer's total load and capacity available from its own generation resources) and follows the customer's metered hourly load.¹⁰
- **Block:** a set amount of power typically received in constant amounts throughout the year. Alternative shapes can be obtained by pairing a block and a Slice product or paying an extra charge for shaping. The customer follows its hourly load.
- **Slice:** a percentage of the FCRPS energy and scheduling flexibility in exchange for shouldering an equivalent percentage of the costs of operating the system.¹¹ For FY02–FY11, 22.5% of the FCRPS output was sold as a Slice product. The Slice percentage has gone up to 27% in the FY12–FY28 contracts. The Slice product is actually a Slice/Block product because customers receive a percentage of the FCRPS energy in addition to a set block amount.

A set percentage of FCRPS output will translate into significantly different energy amounts in a dry year versus a wet year. Thus, the Slice product transfers the risk of hydrologic variability from Bonneville to the customer. In return, the customer has more short-term flexibility regarding how to use its share of excess power or how to manage deficits during periods of low FCRPS water availability. In the FY12–FY28 contracts, 16 preference customers have chosen the Slice/Block product, 1 opted for the Block product, and the rest (116 customers) have contracted a Load-Following product. For Slice customers, their cost is calculated as a

⁹ They are 20-year contracts but signed three years before power service starts so that the power service duration is actually 17 fiscal years.

¹⁰ Regardless of the product, Bonneville serves all preference customers' net requirements. The main distinction between the Load Following product and the rest of products is that, for the Slice/Block and Block products, net requirements are forecasted in an annual basis and the customer then uses its own resources to follow its hourly load.

¹¹ Scheduling flexibility means that the customer can request—within the limits established by other operational requirements—in which month, day, and hour to get its FCRPS energy delivered.

percentage of the total costs associated with operating the FCRPS. For the remaining preference customers, Tier 1 rates have multiple components: a monthly customer charge depending on the type of product, a monthly demand charge (or credit) depending on customer's peak demand, and a load shaping charge reflecting FCRPS hydropower availability variations from month to month and between day and night hours. Through power sales to its preference customers (Slice and non-Slice) at Tier 1 rates, Bonneville recovers not only the cost of producing power from the FCRPS but also the costs of implementing programs derived from the obligations set out by the Northwest Power Act. Depending on wholesale market price trends and Bonneville's expenditures under the various programs whose costs are recovered via Tier 1 rates, it is not impossible for Tier 1 rates to surpass Tier 2 rates.

Tier 2 power originates from Bonneville's power purchasing agreements (PPAs) and short-term or long-term market purchases. These rates reflect Bonneville's marginal cost of power. Tier 2 power only comes in the block shape. Several variations of Tier 2 rates are available. For instance, customers can choose whether they want their Tier 2 power rates to reflect the cost of Bonneville's purchases of renewable power or an average of a portfolio of Bonneville's purchases.

A summary of the current average undelivered rates for the different types of priority firm customers is presented in Table 3.2 (BPA 2015a).¹² The rates paid for power delivered by Bonneville vary from customer to customer for a variety of reasons. First, Tier 1 rates have multiple components that depend on the shape of the load and the products and services chosen by each customer. Second, customers can also choose among multiple Tier 2 rates. In addition, power sold to the IOUs that participate in the Residential Exchange Program, to DSI customers, or to new resources is sold at yet different rates.

Table 3.2. Bonneville FY14–FY15 rate schedule summary

Tier 1 power for preference customers	33.32 mills/kWh ¹³
Tier 2 charges	39.86 mills/kWh
Priority firm exchange (for customers of IOUs enrolled in the Residential Exchange Program)	59.13 mills/kWh ¹⁴
Industrial firm (for DSI customers)	38.97 mills/kWh
New resource ¹⁵	77.65 mills/kWh

Note: 1 mill = \$0.001

Table 3.2 shows that, on average, preference customers paid 33.32 mills/kWh in FY14–FY15. In nominal dollars, that is the highest priority firm rate in Bonneville's history. However, adjusted for inflation, the highest actual effective priority firm rate of 38.51 mills/kWh corresponds to FY2003. From 2004 to 2009 the effective rate decreased. On the other hand, since 2009, the priority firm rate has been following an increasing trend (BPA 2015b).

¹² Undelivered rates do not include the cost of transmission.

¹³ Forecast effective rate for non-Slice Tier 1 power purchases.

¹⁴ In the Residential Exchange Program, BPA purchases a preset amount of power from the IOUs at their average system cost and sells it an equivalent amount at the (lower) priority firm exchange rate. The credit obtained by the IOUs must be passed through to the residential and farm customers.

¹⁵ The New Resource rate applies to IOUs for loads that do not qualify under the Residential Exchange Program or to power requested by preference customers to serve any new large single load, as defined by statute.

3.2 Future Climate in the Bonneville Region

This section presents the projections of future hydroclimate conditions in the Bonneville region. Projections based on multimodel ensemble runs are summarized in terms of mean annual and seasonal changes (i.e., spring, summer, fall, and winter) in temperature, precipitation, runoff and evapotranspiration for near-term future (2011–2030) and midterm future periods (2031–2050) as compared to the baseline period (1966–2005).

3.2.1 Regional Climate Projections

The projected annual temperatures for baseline (1966–2005) and future periods (2011–2030 in near-term and 2031–2050 in midterm) are illustrated in Fig. 3.2, with gray lines showing the annual mean temperature from ten downscaled (and bias-corrected) climate models for both 1966–2005 baseline and 2011–2050 future periods, the green line representing the multimodel median, and the black line showing the 1981–2012 Daymet temperature historical observation. The corresponding multimodel probability distributions in the baseline and future periods are compared in the right panel. A two-sample Kolmogorov-Smirnov test at the 5% significance level is used to determine if the difference between baseline and future periods is statistically significant.

This type of interannual plot shows the range of variability and trend made by each model. This makes it possible to observe whether the projected trend and variability are consistent with historic observation. Since climate models are not meant to reconstruct the exact timing of the historic interannual and decadal variability, the model runs are not expected to fully follow historic interannual values. The same condition applies when interpreting similar interannual plots of precipitation, runoff, and generation.

In all four assessment areas (BPA-1 to BPA-4), the increasing trend in the ensemble mean annual temperature is similar to the observed trends, although with a large intermodel variability (Fig. 3.2). The large ensemble variability is projected, and it provides a good example illustrating why a multimodel ensemble approach must be used to understand the overall picture. In the two future time periods (2011–2030 near-term and 2031–2050 midterm), annual mean temperature across all Bonneville areas is also projected to continue to increase. Moreover, comparison of the probability distributions of multi-model mean annual temperature for the future and baseline time period also show a statistically significant warm shift for the 2011–2050 time period in all BPA areas (Fig. 3.2).

The annual and seasonal changes of temperature are further summarized in Fig. 3.3. Change is defined as the degree difference (F) of future periods (2011–2030 and 2031–2050) when compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of the box indicating the 25th and 75th percentiles, and the whiskers extending to the lowest/highest models. When compared to the baseline period (Fig. 3.3 and Appendix D), greater increases in annual and seasonal mean temperatures are projected in the summer (June–August) in all study areas.

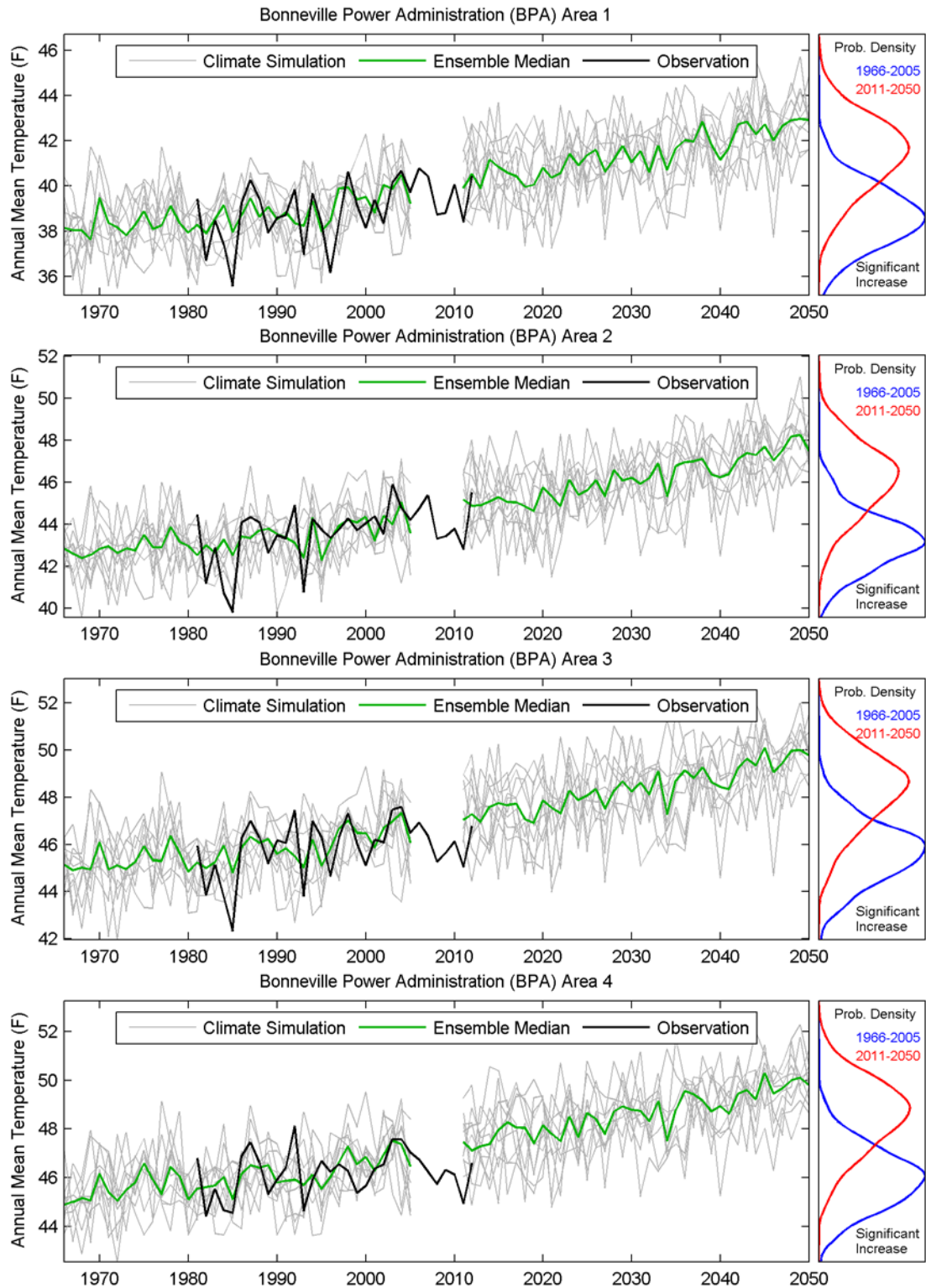


Fig. 3.2. Projected annual mean temperature in the Bonneville region.

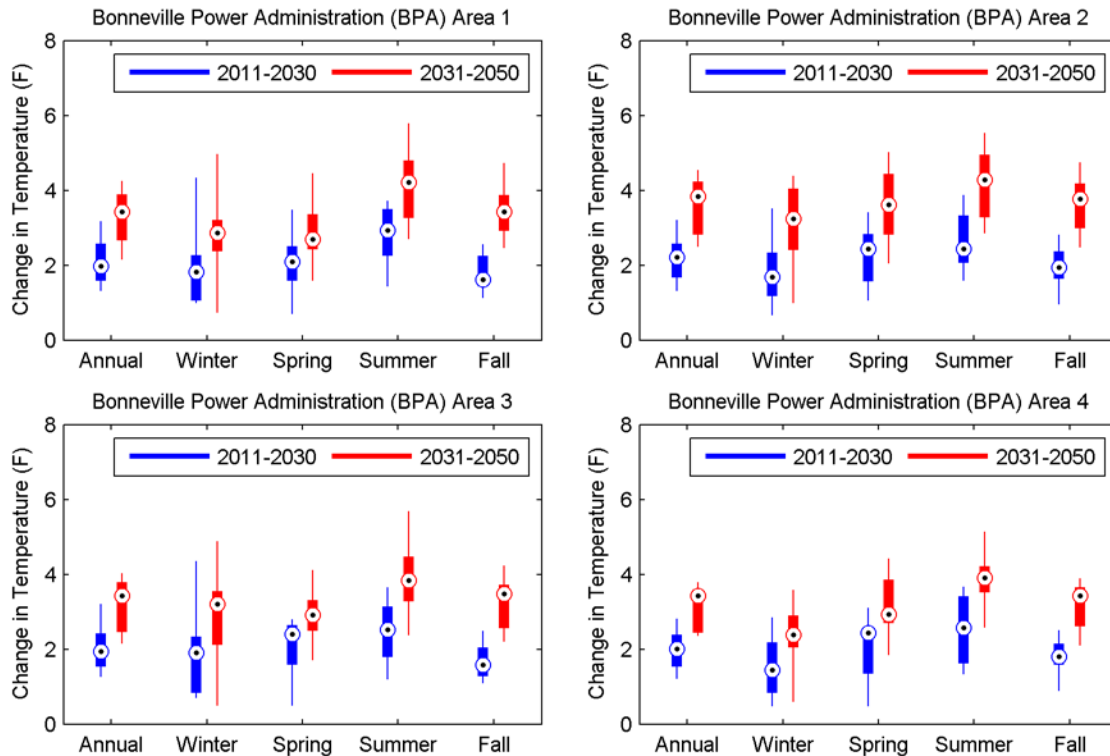


Fig. 3.3. Projected change of annual and seasonal mean temperature in the Bonneville region.

A relatively larger increase in temperatures is shown as compared to the baseline in the midterm future period. The multimodel median annual temperature for Bonneville is projected to increase by about 2.0 °F to 2.5 °F for the near-term and 3.5 °F to 4.5 °F for the midterm relative to the baseline period (Fig. 3.3 and Appendix D). The summer season is projected to warm the most (~4 °F for the midterm), while in other seasons the projected increase in ensemble median temperature is about 3 °F across all Bonneville areas in the midterm future period. While the increase in temperature may not have a strong influence directly on annual runoff (see sensitivity analysis in Section 2.4.4), it causes earlier snowmelt and a shifted seasonal pattern of runoff that will be discussed in the next subsection. This temperature-triggered earlier snowmelt effect is among one of more certain findings in future climate projections.

Interannual and intermodel annual precipitation projections have larger variations than temperature (Fig. 3.4). Comparing the probability distributions of annual precipitation for the baseline and future time periods, a statistically significant increase in precipitation is projected for BPA-1 through BPA-3 areas. For BPA-4, a slight decreasing shift in annual precipitation is projected but it is not statistically significant. Nevertheless, given the high natural variability of precipitation, it would be more difficult to distinguish the consistent long-term climate change signals from near-term and midterm climate projections. This has been a constant challenge in most of the hydro-climate studies and this challenge will likely continue.

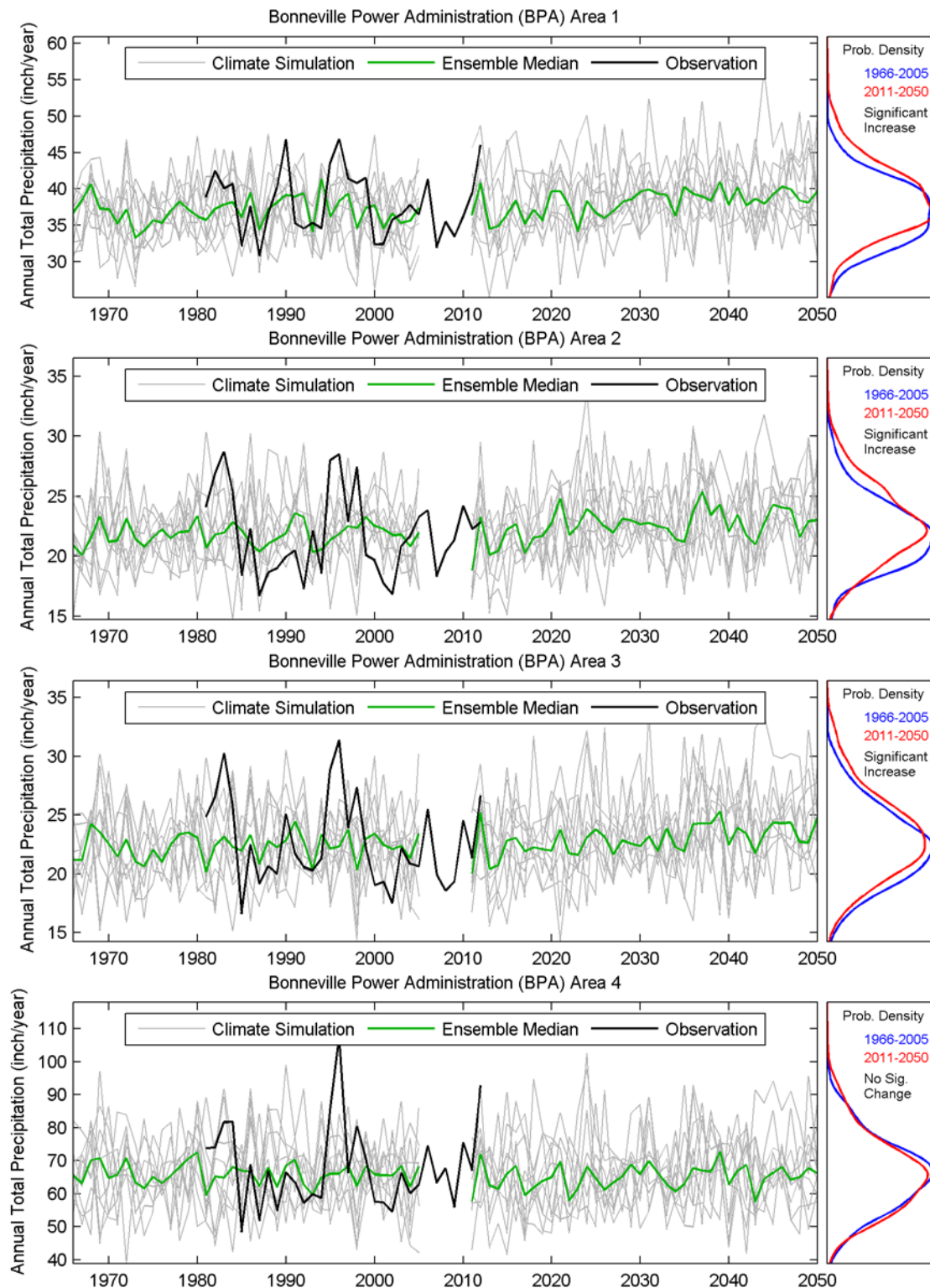


Fig. 3.4. Projected annual total precipitation in the Bonneville region.

The annual and seasonal changes of precipitation are summarized in Fig. 3.5. In general, increase in winter and spring precipitation is projected (despite the large multimodel variability). In the near-term future period (2011–2030), the ensemble median precipitation shows nearly no change in winter, spring, and summer seasons, except in fall season where a small decrease is projected (Fig. 3.5 and Appendix E). In contrast, in the midterm future period (2031–2050), a general increase in precipitation, particularly in the winter and spring, is projected across most of the Bonneville areas (except for summer in BPA-4). The increase in precipitation is more pronounced in BPA-1 area, where precipitation increases in all seasons. For BPA-4, decrease in precipitation is projected in summer and fall, but with a large multimodel variability. Since BPA-4 is a collection of smaller watersheds west of the Cascade Mountains, the slightly different behaviors comparing to BPA-1 to BPA-3 can be expected.

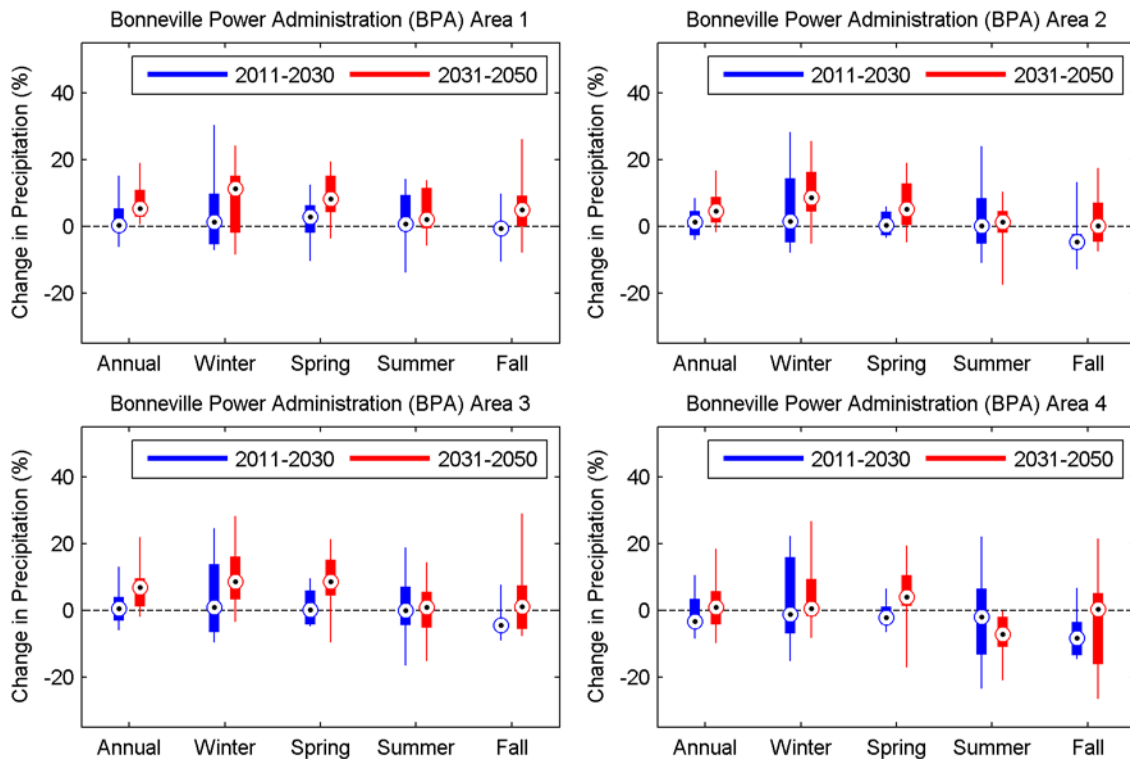


Fig. 3.5. Projected change of annual and seasonal total precipitation in the Bonneville region.

In all Bonneville study areas, the more important signals of change include: (1) increase in temperature in all seasons, and (2) increase in precipitation in winter. While decrease or no change of precipitation is also projected in summer, the impacts to hydropower are less obvious since summer is already the dry season in the Bonneville region. The main contributor to the summer streamflow is due to runoff and snowmelt, which will be discussed in the following section. Given that the trajectory of change (baseline to near-term to midterm periods) is consistently away from the reference line, the impact of these changes will have important implications for future water availability in the Bonneville region as discussed in Section 3.2.2.

3.2.2 Regional Hydrologic Projections

Changes in hydrologic variables (e.g., runoff and evapotranspiration) are mainly driven by changes in temperature and precipitation. As shown in previous studies (Moet et al. 2005, Mote 2006), increases in temperature have already resulted in earlier spring snowmelt and delayed winter snowfall, particularly in the western US. Changes in the distribution of precipitation may also affect the total amount of water flowing in the rivers, occurrence of peak runoff, and risks for more floods and prolonged drought events (Peterson et al. 2013).

The runoff responses to projected climate are illustrated in Fig. 3.6 and Fig. 3.7. In Fig. 3.6, the gray lines show the annual total runoff from ten downscaled climate models for both 1966–2005 baseline and 2011–2050 future periods and the green line indicates the multimodel median. The 1981–2012 historical observation from WaterWatch is shown as a black line for comparison. The corresponding multimodel probability distributions in the baseline and future periods are compared in the right panel. A two-sample Kolmogorov-Smirnov test at the 5% significance level is used to determine if the difference between baseline and future periods is statistically significant. Consistent with projected precipitation variability, the interannual variability in total runoff is higher, but the probability distribution of annual runoff projection shows slight increasing shifts in BPA-1–BPA-3, except in BPA-4 where a slight decrease of total runoff is projected. Nevertheless, none of the increasing and decreasing shifts in total runoff are statistically significant (Fig. 3.6). The effect of the rising temperature on the total runoff is clearly seen in the monthly hydrograph of the projected 90th, 50th, and 10th percentiles of the monthly runoff in Appendix F, which shows a shift in the peak runoff from June in the baseline period to the month of May in the future time periods. This shift is more pronounced in BPA-1–BPA-3. It should also be noted that while trends are apparent in the four BPA study areas, there is large spread in interannual variability consistent with historic and current variability.

The strongest change projected in total runoff over Bonneville for both future periods is the increase in winter and the decrease in summer (Fig. 3.7) in all areas. The projected changes in Fig. 3.7 are in percentages relative to the 1966–2005 baseline runoff. Increases in spring runoff are also projected in BPA-1 and BPA-2 in both future time periods, whereas in BPA-3, there is a decrease in projected spring runoff in the near-term period but an increase is projected in midterm future time period. In contrast, BPA-4 shows a decrease in spring runoff in both future periods. Ensemble members exhibit negative mean annual changes in the near-future period and positive mean annual changes in the midterm future periods. Fig. 3.7 does show uniformly negative projected changes on the order of 20–30% in summertime runoff for all models for both time periods. These projections could possibly relate to trends already observed in SWE and earlier snowmelt runoff in the region (Hamlet et al. 2010, Mote 2006). The Cascade Mountains assessment area (BPA-4) stands out with the largest projected decreases in summertime runoff. The projected decrease in summertime runoff is also consistent with little-to-no changes in summer precipitation and with increasing summertime drying due to higher evapotranspiration as shown in Fig. 3.8.

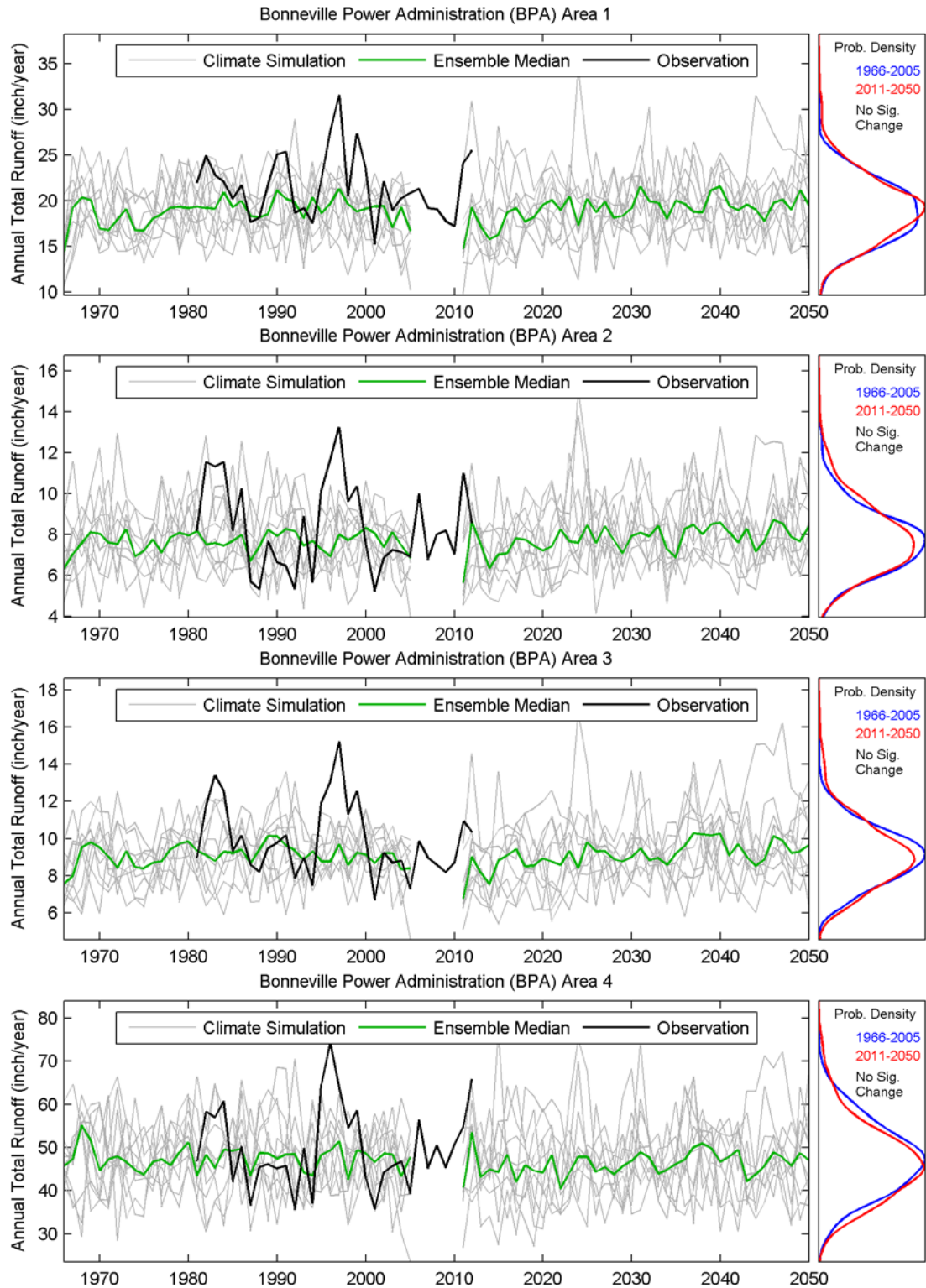


Fig. 3.6. Projected annual total runoff in the Bonneville region.

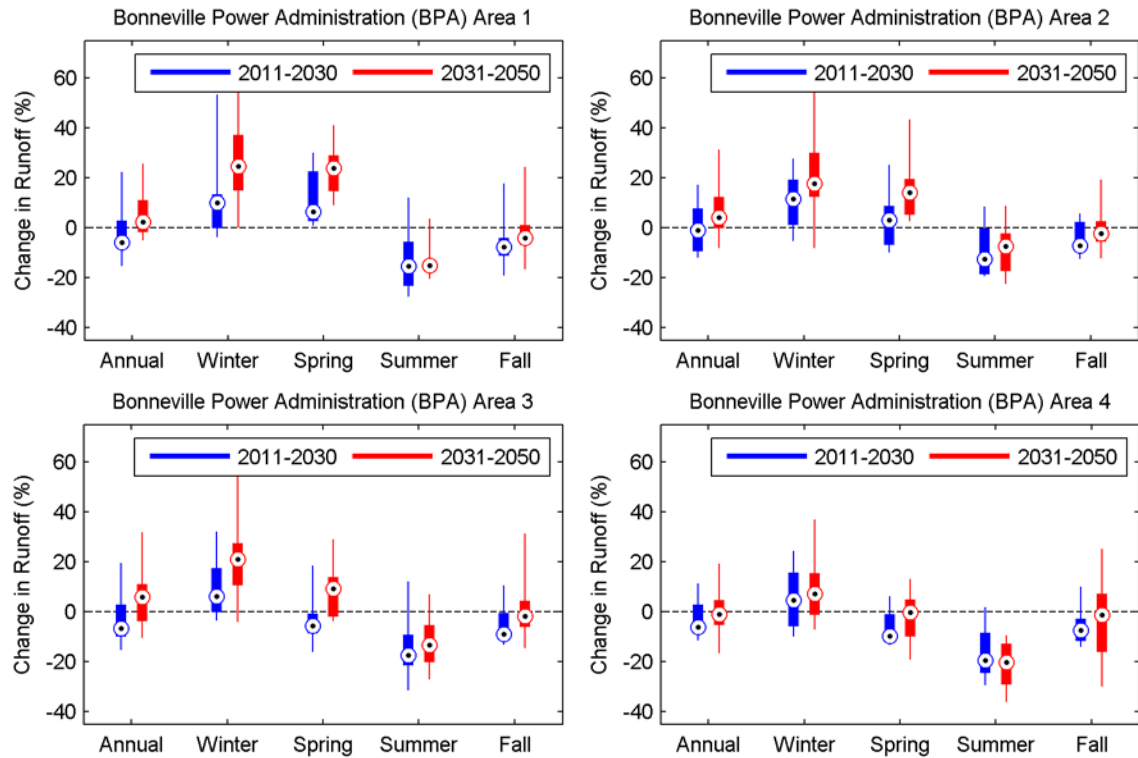


Fig. 3.7. Projected change of annual and seasonal total runoff in the Bonneville region.

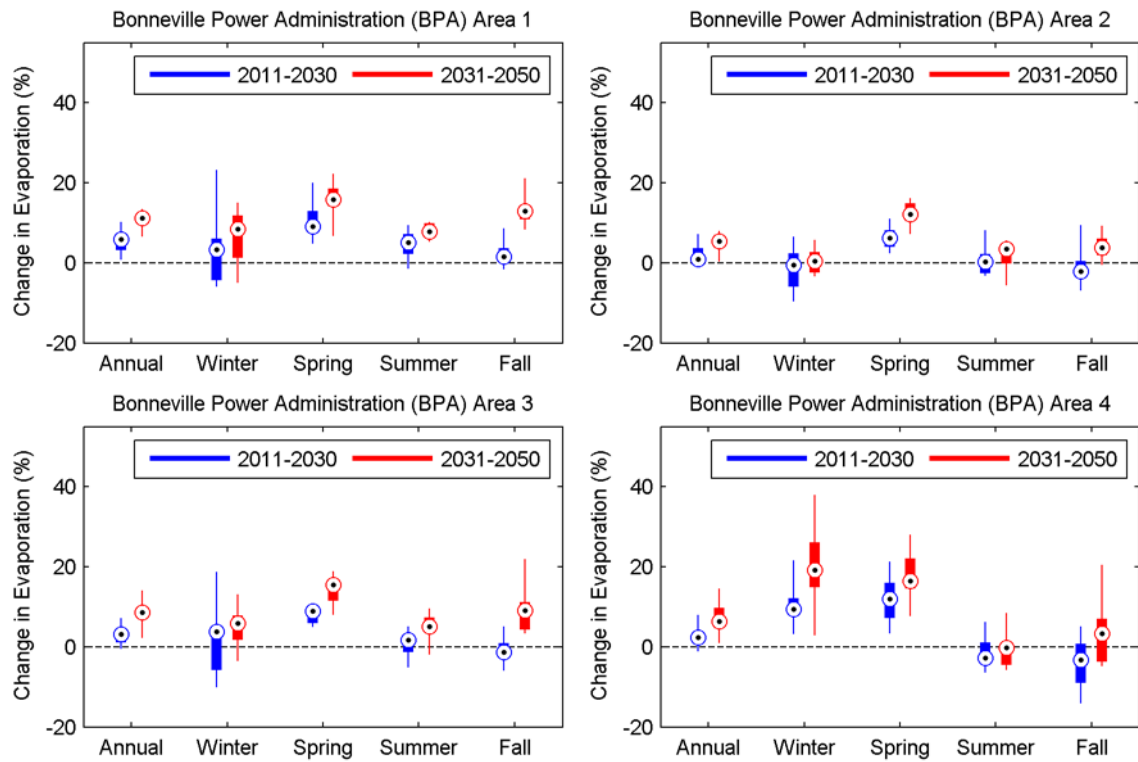


Fig. 3.8. Projected change of annual and seasonal total evapotranspiration in the Bonneville region.

In Fig. 3.8, the change is defined as the percentage difference (%) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. On a seasonal basis, most increases in evapotranspiration are projected to occur in the winter and spring in all BPA areas, and they appear to be primarily driven by increasing temperatures and available soil moisture from increased precipitation and snowmelt. However, decreased runoff combined with low summer precipitation produces a summer decrease in soil moisture, resulting in little to no change in summer evapotranspiration.

In Bonneville, these changes in hydrological regimes are primarily associated with a decrease of more than 50% in ensemble median average April 1st SWE (Fig. 3.9, 2011–2050 future to 1966–2005 baseline) and a reduction in snow-covered days that are projected to decrease in the western regions (25 days/year). The change is defined as the percentage difference (%) for the April 1st SWE and the maximum SWE and absolute difference (future – baseline) for the annual snow-covered days of the 2011–2050 future period comparing to the 1966–2005 baseline period. All grid cells in which long-term (i.e., average across the 1980–2012 control run) April 1st SWE was greater than 5 mm were identified and used as a spatial filter to summarize the simulated April 1st SWE, the snow-covered days, and the annual maximum SWE for each model and for both baseline and future periods. The reduction in snow-covered days, despite the increase in winter precipitation, is primarily driven by an increase in the projected winter temperature in these regions, which may increase the frequency of freeze-thaw cycles and the likelihood of accelerated melt rates and more rainfall than snow events. Such changes in snow hydrology, combined with changes in the runoff regime, suggest that more water is available to runoff earlier in the spring, and this may result in lower streamflow conditions in the summer in all Bonneville areas.

An additional analysis on extreme runoff is shown in Fig. 3.10, which presents future changes in ensemble median high runoff (i.e., 95th percentile of daily runoff) and median low runoff (i.e., 5th percentile of running 7-day average runoff) for both future projection periods. Reductions in both high and low runoff are projected in the near-term period (Fig. 3.10a and c), suggesting that potential drier conditions are projected. However, increases in both high and low runoff are projected in the midterm future (Fig. 3.10b and d), most notably in the BPA-2 and BPA-3 areas, whereas a decrease in low runoff is projected in the upper Columbian basin (BPA-1). These results suggest the possibility of more frequent flood events which may increase the difficulty of water management in the future climate condition

3.2.3 Comparison with Other Climate Studies in the Region

Due to factors such as the differences in spatial domain (e.g., the four Bonneville study areas do not cover the entire Pacific Northwest [PNW] Region), GHG emission scenarios, climate models, definition of baseline and future periods, and downscaling and bias-correction approaches, the hydroclimate projections summarized in this study may not be directly comparable with findings from other available studies (discussed below). Nonetheless, some qualitative statements and comparisons can be made.

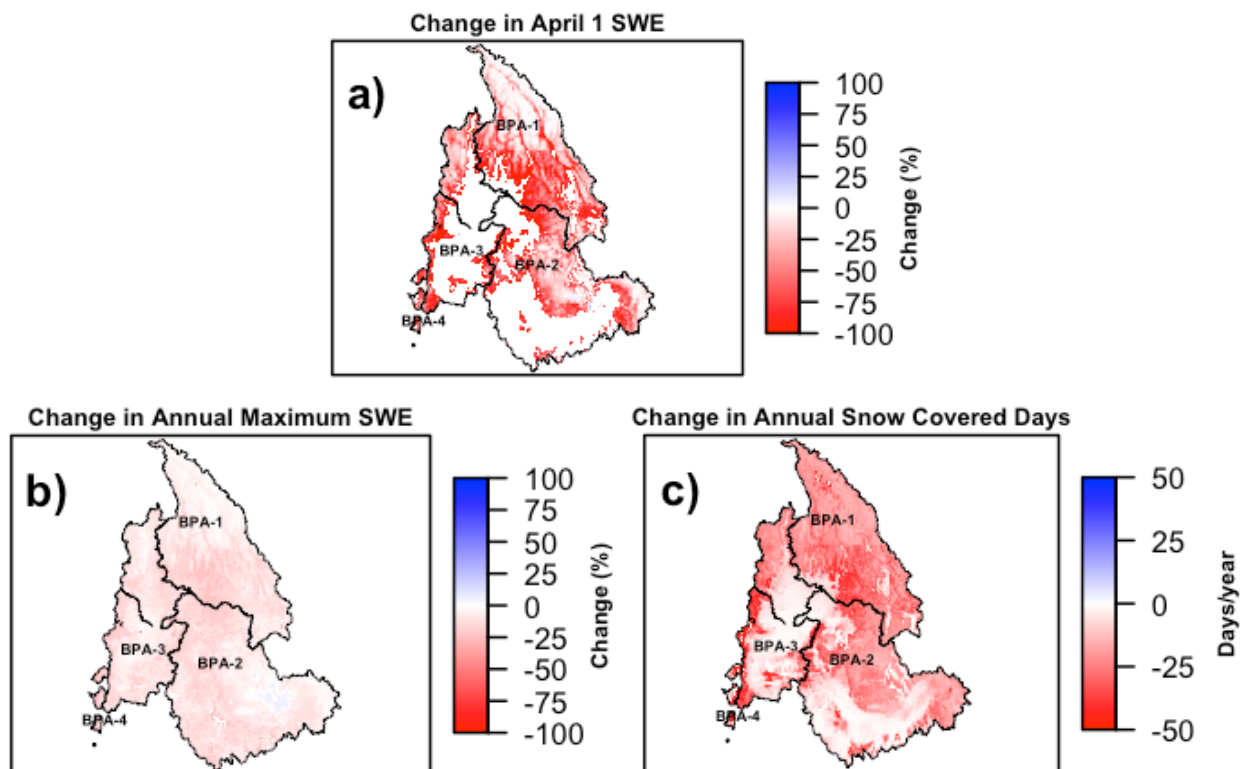


Fig. 3.9. Spatial distribution of multimodel ensemble median change in (a) April 1st SWE, (b) annual maximum SWE, and (c) annual snow-covered days in the Bonneville region.

Despite the uncertainties in future climate projections, previous studies on climate change found a general consensus about a temperature increase in the western US (Kunkel et al. 2013d, Dalton et al. 2013, Mote and Salathé Jr. 2010). Using the CMIP5 models, Dalton et al. (2013) found a projected increase of at least +0.5 °C (+0.9°F) in every season by all models in the PNW Region (2041–2070 relative to 1950–1999), with mean annual warming ranges from +1.1 °C to +4.7 °C (+2 °F to +8.5 °F). Their models also projected greater warming in the summer of about +1.9 °C to +5.2 °C (+3.4 °F to +9.4 °F) under the RCP8.5 scenario.

Kunkel et al. (2013d) used multiple CMIP3 models to evaluate the future climate conditions of six large regions in the contiguous US. In addition to 15 selected CMIP3 GCMs, Kunkel et al. (2013d) also utilized 11 GCM-RCM based projections as part of the North American Regional Climate Change Assessment Program (NARCCAP). They provided projections for each GCM-RCM combination for the periods of 1971–2000, 1979–2004 and 2041–2070 using high (A2) emission scenario at a resolution of approximately 50 km. The PNW Region defined in Kunkel et al. (2013d) encompasses the four Bonneville study areas except for the upper Columbian Basin in BPA-1 in Canada. For temperature change, Kunkel et al. (2013d) showed an increase of +1.5 °F to +3.5 °F by 2035, while the increase ranges between +2.5 °F to +4.5 °F by the end of 2055 for the low emission scenario and between +2.5 °F to +5.5 °F for the higher emission scenarios based on multi-CMIP3 model projection. Using the NARCCAP projections, the 2041–2070 temperature is projected to increase by +3.0 °F to +5.0 °F, with the greatest increase in summer, ranging from +3.5 °F to +6.0 °F. These results are generally consistent with the

projections of overall increases in mean annual air temperature and greater summer warming described in Section 3.2.1

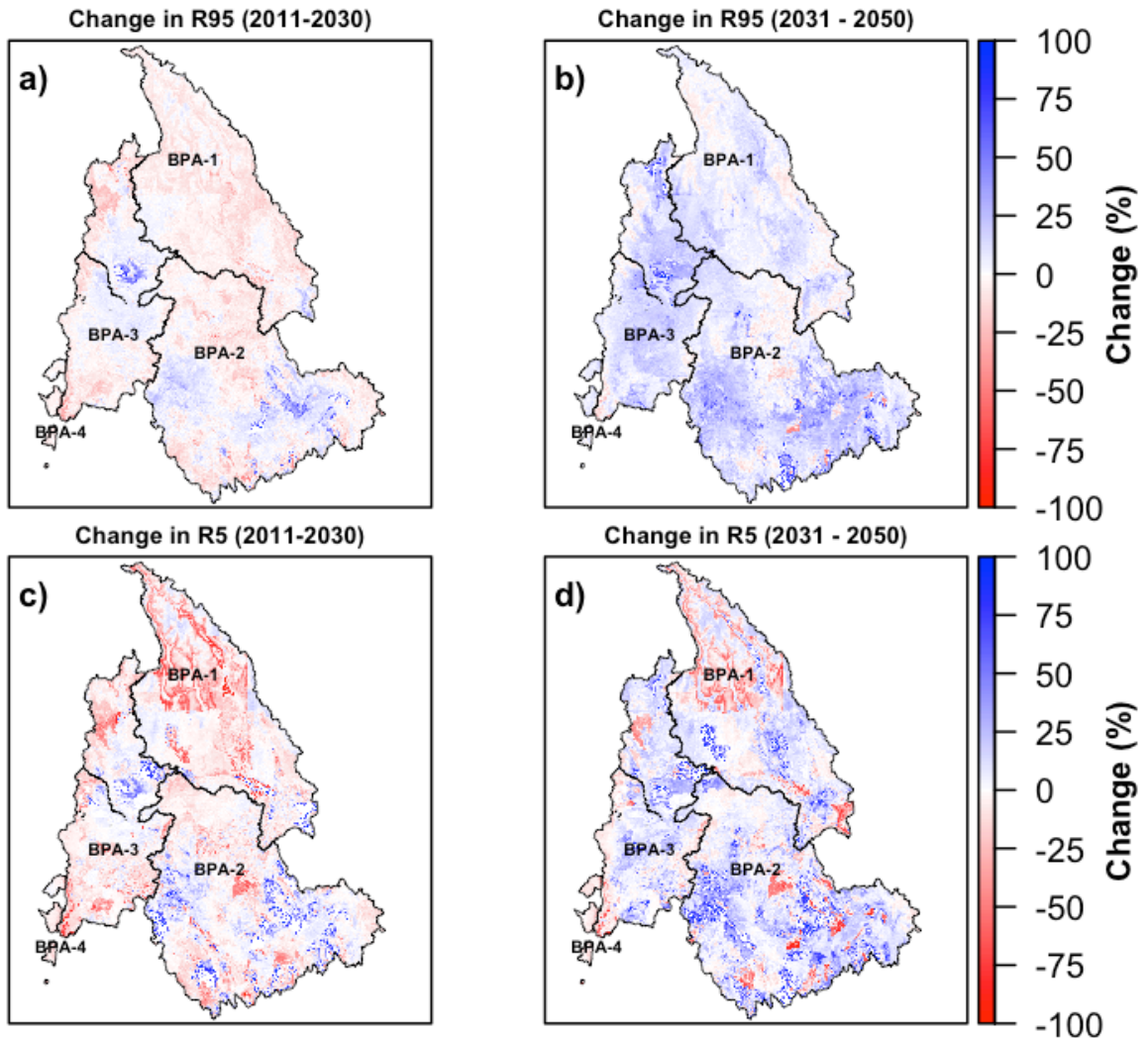


Fig. 3.10. Spatial distribution of multimodel ensemble median percentage change in (a) high runoff in 2011–2030, (b) high runoff in 2031–2050, (c) low runoff in 2011–2030, and (d) low runoff in 2031–2050 time periods in the Bonneville region.

For precipitation, Dalton et al. (2013) showed an annual average precipitation increase of about +3%, with individual models ranging from –4.7% to +13.5%. The majority of the model projections in their ensemble show increases in the winter, spring, and fall precipitation, and a majority project decreases in summertime precipitation. Similarly, NARCCAP (Kunkel et al. 2013d), which provides results from the CCSM3 coupled with the Canadian Regional Climate Model (CRCM) and the Fifth-Generation Penn State/NCAR Mesoscale Model (MM5), also projected decreases in summertime precipitation for the 2041–2070 time period. In contrast, in terms of summertime precipitation projection simulated in this study, the multimodel median is around no change except in BPA-4, where a decrease in precipitation is projected.

The Columbia Basin Climate Change Scenarios Project (CBCCSP) (Hamlet et al. 2013) uses 77 hydrologic model scenarios (covering 2030–2059) based on data from ten GCMs, two emissions scenarios (A1B and B1), and three downscaling methods, encompassing 297 streamflow locations in PNW region. The Hamlet et al. (2013) study showed shifts in streamflow timing from spring and summer to winter associated with decreases in spring snowpack in basins with significant snow accumulation in winter, generally consistent with the snow projections described in Section 3.2.2. Based on CBCCSP, Tohver et al. (2014) further analyzed changes in extreme hydrologic events and showed a projected increase in floods and low flow intensity for most of the sites in these regions, but the largest increases are projected in the basins dominated by mixed rain and snow.

Furthermore, the RMJOC (reviewing body for the Columbia-Snake River Basin activities of Bonneville, USACE, and Reclamation) study (RMJOC 2010) also used the CBCCSP projections in their reports. RMJOC (2010) runoff projections for 2010–2039 showed increases in winter to early spring runoff ranging from about +20% to >50%, depending on the scenario. This is generally consistent with the runoff projection discussed in Section 3.2.2. The RMJOC study, however, projected relatively little change in the summertime runoff (from 0 to –10%, depending on the scenario). This contrasts with the 9505 assessment, which generally projects more significant decreases in summertime runoff (Fig. 3.7). The difference could be caused by several factors, such as different summertime precipitations projected by different models and the different models setups in these two studies. Some further comparison of this assessment’s projections and the Brekke et al. (2013) CMIP5 projections is illustrated in Appendix C.

3.3 Climate Effects on Federal Hydropower in the Bonneville Region

This subsection discusses how the projected hydroclimate change may affect federal hydropower generation in the Bonneville region. The projected change of annual and seasonal generation is presented in Section 3.3.1. The potential risk to hydropower marketing is discussed in Section 3.3.2.

3.3.1 Projections of Hydropower Generation

Using the WRES model described in Section 2.5, the projection of monthly generation and watershed storage in the Bonneville region are calculated for each of the ten downscaled climate models. Projections based on multimodel ensembles are summarized in terms of the mean annual and seasonal changes (i.e., spring, summer, fall, and winter) for the near-term future (2011–2030) and midterm future (2031–2050) periods as compared to the baseline period (1966–2005).

The interannual variability of annual hydropower generation for the baseline and future periods are shown in Fig. 3.11, with gray lines showing the annual total generation from ten downscaled climate models for both 1966–2005 baseline and 2011–2050 future periods, the green line representing the multimodel median, and the black line showing the 1981–2012 historic observation from EIA and PMAs. The annual and seasonal change of hydropower generation is further summarized in Fig. 3.12. The change in Fig. 3.12 is defined as the percentage difference (%) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of box indicating the 25th and 75th percentiles, and whiskers

extending to the lowest/highest models. The monthly multimodel 10th, 50th, and 90th percentiles of generation and watershed storage are shown in Appendices H and I for further illustration.

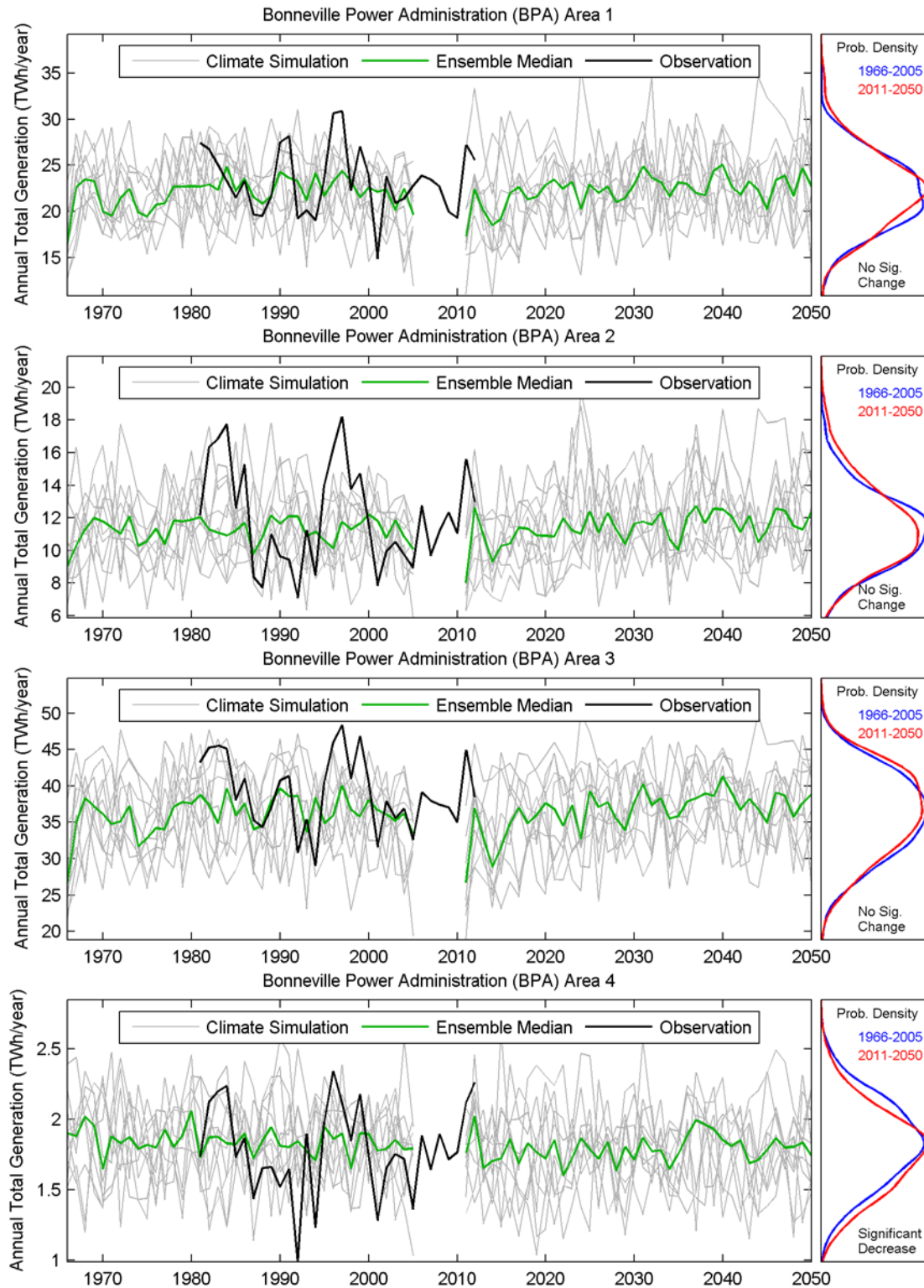


Fig. 3.11. Projected annual total generation in the Bonneville region.

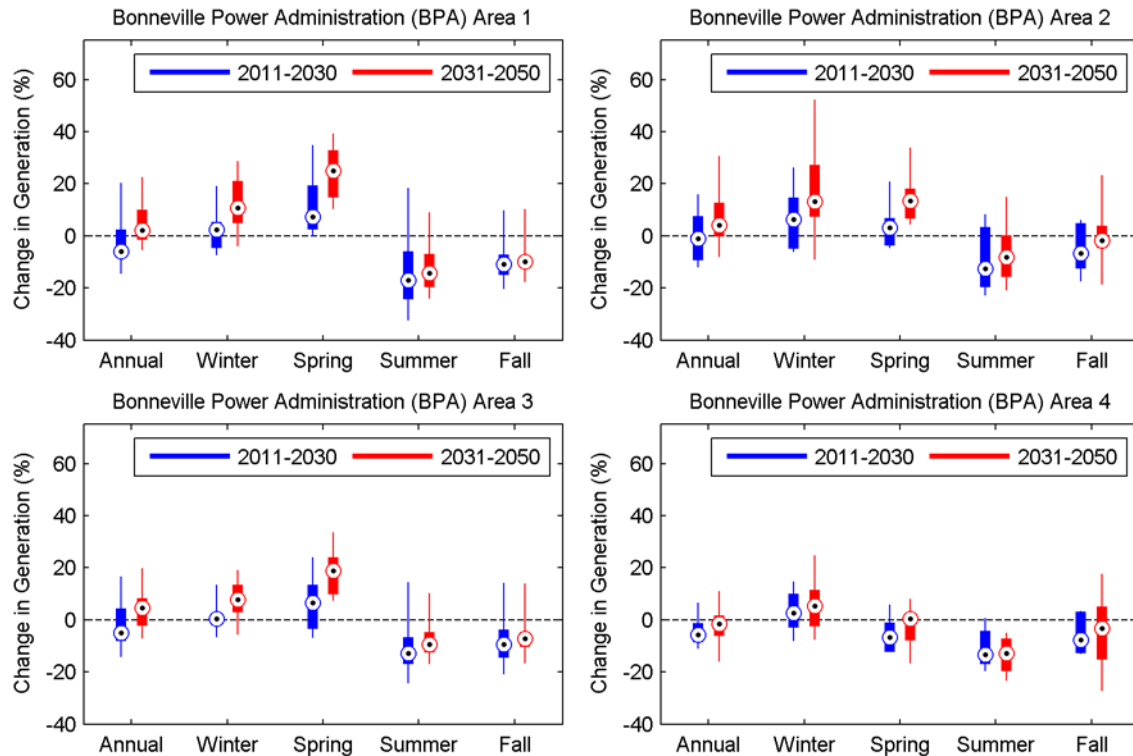


Fig. 3.12. Projected change of annual and seasonal total generation in the Bonneville region.

No noticeable interannual hydropower generation trend is found in all of four assessment areas (BPA-1 to BPA-4) during the baseline period (Fig. 3.11). Given that there is no noticeable trend in the baseline runoff and precipitation, such a result is expected. It should be noted that the WRES model is developed and calibrated using the 1981–2012 hydropower, hydrology, and meteorology data, and hence it can only simulate how a current and stable hydropower system (i.e., without significant change of installed capacity) may react to change of different meteorological and hydrologic inputs. This corresponds to one special feature of the US federal hydropower system: since the 1970s, there has been limited change of the total installed capacity (Kao et al. 2015). This lack of change in the federal hydropower system resulted in a rather stationary generation of data that may enable development of a simplified hydropower model such as EBHOM (Madani and Lund 2009 and 2010) or WRES in this study. With WRES' model limitations in mind, the simulated 1966–1980 generation represents how a current (i.e., 1981–2012) hydropower system would respond to the simulated 1966–1980 runoff and precipitation. Therefore, the simulated 1966–1980 generation does not reflect the expanded capacity during that period. It only serves as a baseline for comparison to future climate projection in this study.

In the two future periods (2011–2030 near-term and 2031–2050 midterm), there was no noticeable annual hydropower generation trend in all of four assessment areas (BPA-1 to BPA-4 in Fig. 3.11). Corresponding to the lower precipitation and runoff projection made by the ten selected climate models in the near-term future period, the annual hydropower generation in the near-term future is projected to decrease (from -1% in BPA-2 to -7% in BPA-3 in terms of multimodel median in Fig. 3.12). With increased precipitation and runoff in the midterm future

(comparing to the near-term), the projected annual hydropower is slightly increased, or there is nearly no change (from +4% in BPA-3 to -1% in BPA-4 in terms of multimodel median).

Overall, the range of variability of future annual hydropower in the Bonneville region is similar to the baseline period (Fig. 3.11). This result may be somewhat counterintuitive given the large seasonal change of runoff (Fig. 3.7). As will be discussed soon, the reservoir storage may provide a buffer to absorb runoff variability and is one main reason of the stable future annual hydropower projection. The finding is consistent with our previous assessment (Sale et al. 2012) that used a different method (Kao et al. 2015). The modeling results suggest that assuming no major change to the current capacity or operation in the federal hydropower system, the range of annual hydropower generation in the near-term and midterm future periods in the Bonneville region can remain in a similar range to the historic observation. However, if there will be more change in the climate condition than that simulated in this study, degradation of the system (e.g., due to aging infrastructure), or drastic change of operation, such findings on future annual hydropower generation may not hold.

Despite the obvious increasing trend of future annual temperature (Fig. 3.2), no related trend is observed in the annual hydropower generation (Fig. 3.11). As discussed in other sections, hydropower is a favored source of electricity generation due to its operational flexibility and lower maintenance costs (i.e., the “fuel” is generally free of charge and renewable). Therefore, when conditions allow, utilities will try to maximize the usage of hydropower before switching to other fuel-dependent energy sources to optimize revenue, especially during daily peak load periods. As a result, at the annual scale, hydropower generation is mainly controlled by water availability (runoff and precipitation) rather than temperature (Kao et al. 2015). Increasing temperature has a larger influence on the hydrologic cycle (e.g., snowmelt and evapotranspiration) and could alter the seasonal characteristics of runoff.

The WRES model provides further opportunity to examine future hydropower generation at seasonal and monthly levels. Unlike annual hydropower generation, the change in seasonal hydropower generation is much more significant. In the near-term future, there is +3% to +10% increase in the winter generation, and the increase jumps to +5% to +22% in the midterm future (Fig. 3.12). Except for BPA-4 (Cascade Mountains receive more precipitation as rain, compared to other Bonneville study areas), a significant increase in spring generation is continued in BPA-1 to BPA-3 (Columbia River projects). Conversely, a big reduction of hydropower generation is projected in the summer (around -20% in terms of multimodel median in both future periods) for all regions. Fall generation is also projected to decrease (around -10% in the near-term and -3% in the midterm) with a large model ensemble spread. The shift in seasonal generation patterns (i.e., higher generation in winter and spring) is likely caused by earlier snowmelt triggered by increasing air temperature.

If comparing the projected annual and seasonal change between runoff (Fig. 3.7) and generation (Fig. 3.11), one may notice the different response between the Columbia River projects (BPA-1 to BPA-3) and the Cascade Mountain projects (BPA-4). In BPA-4, the change of generation mostly follows the change of runoff, but in a slightly smaller magnitude (e.g., the multimodel median summer runoff reduction is around -20%, while the summer generation reduction is around -18%). In BPA-1 to BPA-3, the change of generation is generally smoother than runoff. For instance, winter runoff is projected to largely increase in the midterm future period (around

+20% in BPA-1 to BPA-3 in terms of multimodel median), but the increase in winter generation is relatively minor (from +10% in BPA-1 to +7% in BPA-3). In addition to the difference in basic hydrology (i.e., rainfall or snowmelt driven runoff), the main distinction here is considered to be storage. The hydropower projects in the Cascade Mountains have smaller storage capacity and hence will follow runoff variability more closely. On the contrary, there is a relatively larger storage capacity in the Columbia River system (e.g., Grand Coulee), and it may absorb part of the runoff variability to help maintain stable hydropower generation. Similar observations can also be made from the findings in other hydropower study areas (Sections 4 to 6). In general, hydropower projects in the Bonneville and Western regions have relatively higher storage, so the magnitude of seasonal hydropower change is less than the magnitude of seasonal runoff change. Conversely, the hydropower projects in the Southwestern and the Southeastern have less storage capacity, so the projected change of seasonal hydropower generation will follow the projected change of seasonal runoff more closely. For hydropower projects with even less storage capacity or that are purely operated in run-of-river mode, their response to runoff variability will be more direct and could be more vulnerable in the projected future climate conditions. Although the watershed storage in WRES is a conceptual variable and does not have a direct linkage to the actual storage in the reservoirs supporting federal hydropower plants, it is able to capture the characteristic of watershed storage in the regional hydropower systems.

For federal hydropower in the Bonneville region, the most important climate change impact is likely to be from earlier snowmelt and change in runoff seasonality. With the increasing winter/spring runoff and decreasing summer/fall runoff, water resource managers will need to allocate the water usage more carefully. The increased generation in the winter may pose no issues for BPA in meeting loads; however, decreased flows and consequently less hydropower production in the summer, along with higher loads, may be an issue. With the relatively larger storage, particularly in the Columbia River projects, the system is likely to be able to absorb part of the runoff variability and hence may continue to provide stable annual hydropower generation in the projected near-term and midterm future periods. However, such findings are based on the assumption that there is no significant change in the future installed capacity and operation. The issues of aging infrastructures and indirect effects may reduce the system's ability to mitigate runoff variability and increase the difficulty of future operation.

3.3.2 Climate Change Impacts on Federal Power Marketing

This section describes (1) the impacts that simulated changes in temperature and precipitation described earlier in the chapter have on federal power marketing by Bonneville, and (2) the interactions between Bonneville and surrounding regional electricity markets and how they might be affected by climate-related changes in federal hydropower generation and the overall generation mix.

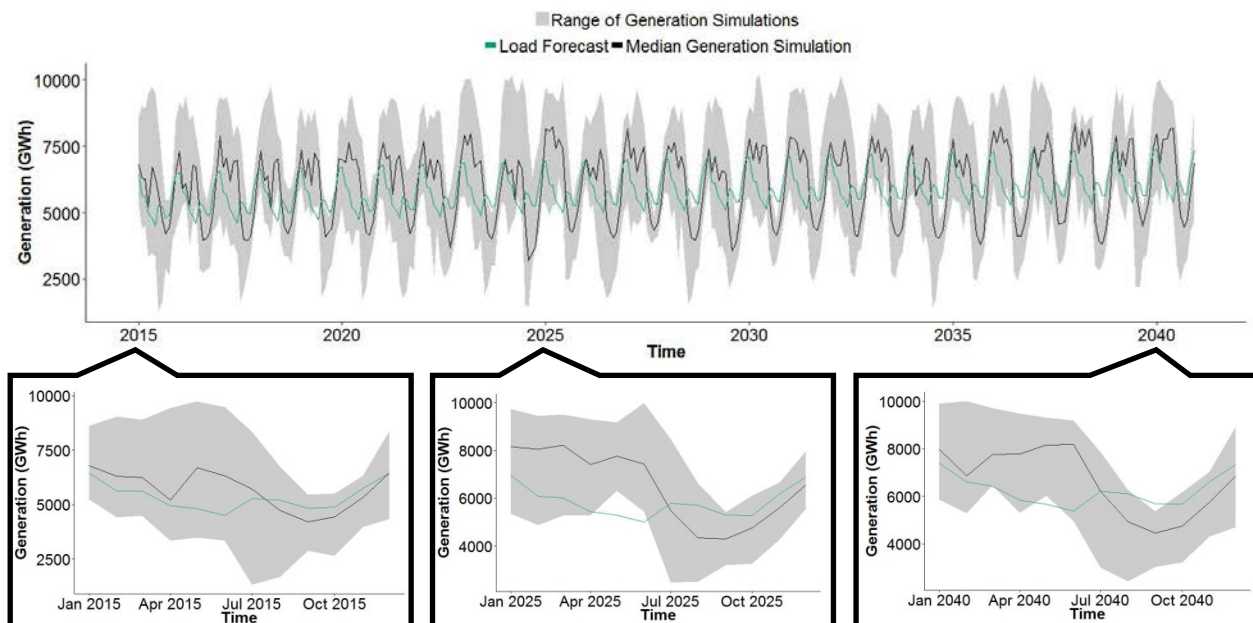
Bonneville serves the net requirements load (i.e., the difference between the customers' total demand and the generation they can obtain from their own resources) of all its preference customers.¹⁶ Under the Regional Dialogue contracts, customers can choose whether they want their load growth to be served by Bonneville at Tier 2 rates or by non-federal resources.¹⁷

¹⁶ However, the rate charged to new large single loads—added after FY1980 and requiring ten average megawatts or more—served by any of Bonneville's preference customers is the higher New Resource Firm Power Rate.

¹⁷ The Slice/Block and Block customers have elected to serve their own load growth, Load Following customers have made

Having to furnish energy to cover the load growth of those customers that request it makes it important for Bonneville to discern whether climate change will increase or decrease total electricity consumption in the PNW.¹⁸ Fig. 3.13 shows the evolution of forecasted load requirements by Bonneville alongside the range of projected hydropower generation made by the WRES model for Bonneville.

The three vignettes at the bottom of Fig. 3.13 zoom in to the projected seasonal generation and load profiles for three years representative of the beginning, middle, and end of the projection period. For the vignette corresponding to the beginning of the projection period, the load is within the range of projected generation in all months. The median generation projection is above the forecasted load in the first seven months of the year and below the forecasted load in the rest of the months. That seasonal relationship between generation and load continues in the vignettes corresponding to later years, but the gaps between median generation and load widen. Surplus power (i.e., generation above what is needed to satisfy demand) increases in late winter and spring, and so does the need for replacement power in the last five months of the year. Total annual generation, based on the median of all projections, is larger than the total annual forecasted load in 22 out of the 26 years displayed in Fig. 3.13, but the size of the surplus decreases over time.



Note: The load forecast was provided by Bonneville and does not incorporate climate change effects.

Fig. 3.13. Bonneville load requirement forecast versus WRES hydropower generation projection (2015–2040).

The average annual growth rate in the load forecast displayed in Fig. 3.13, which does not incorporate climate change effects, is 0.6%. Estimates from the literature inform, at least qualitatively, what the temperature-induced changes in demand would be. Hamlet et al. (2010)

mixed elections (BPA, 2015a).

¹⁸ <http://www.dictionaryofengineering.com/definition/electrical-load.html>. In this document, the terms *load* and *demand* are used interchangeably when referring to electricity consumption.

project increases in electricity demand for heating and cooling purposes in the PNW out to 2080, taking into account changes in temperature, population growth, and—for cooling demand—AC penetration. Even though heating demand per capita decreases, total heating demand increases due to population growth. In the summer, cooling demand increases both per capita and in total, but the PNW remains a winter peaking system (i.e., hours with the greatest electricity demand happen during the winter months). For neighboring British Columbia, Parkinson and Djilali (2015) find that reductions in heating demand are likely to more than offset increases in cooling demand. However, since no changes in air conditioning penetration are being considered, the authors acknowledge that the increase in summer demand might be understated in these results. In practice, the list of variables used by electricity system planners to generate load forecasts is larger than that used in these two papers. In both cases, the focus is on estimating the size of the temperature effect rather than the net effect of all hydroclimatic and socioeconomic drivers of electricity demand.

On a per capita basis, these studies coincide in that the temperature-induced effects in demand would entail a decrease during winter and an increase in the summer. These changes do not correlate well with the projected seasonal changes in generation shown in Fig. 3.13, namely increases in late winter and spring but decreases in the summer. Ideally, Bonneville would like to store the excess winter runoff and schedule it for generation during summer peak hours. However, there is not enough reservoir capacity in the FCRPS to carry the ideal (from a hydropower generation perspective) volume of water from winter to summer while complying with flood control requirements regarding reservoir elevation. Thus, to match the seasonal shape of its generation to that of its contracted demand, Bonneville will have to increase its surplus power sales during the high-flow season and purchase more replacement power during the low-flow summer months. In order to determine whether Bonneville's net annual revenue from wholesale market transactions—the difference between surplus power sales revenue and replacement power purchase expenditures—would increase or decrease, regional price projections would be required.

Climate-related hydrologic changes impact the quantity of Tier 1 power that Bonneville can make available to its preference customers, as well as the rates at which it is sold. Bonneville's Tier 1 rate for FY14 and FY15 (33.32 mills/kWh) continues to be lower than the average wholesale price of 38.5 mills/kWh (EIA 2015). However, the difference between both price points has been shrinking in recent years. Northwest Requirement Utilities and Public Power Council (PPC), two organizations that represent the interests of Bonneville's customers, have expressed concern over the pace at which Bonneville's firm power Tier 1 rates have been increasing. The recent increases have run counter to the decline in wholesale market prices and have a net detrimental effect on the competitiveness of federal hydropower versus alternative sources of energy in the region (PPC 2015). The reasons cited for the increases in Tier 1 rates in the past three rate cases (FY10–FY11, FY12–FY13, and FY14–FY15) include the implementation of the energy efficiency and fish and wildlife programs, expenditures related to upgrades and rehabilitation of hydropower plants, and a lower than forecasted surplus of power revenues.

Projected climate-related changes in the availability and timing of FCRPS generation suggest higher replacement power purchase expenditures. Unless those expenditures can be offset by larger surplus power sales revenue, the increased expenditures will have adverse effects on Tier

1 rates. Moreover, if climate change results in additional fish and wildlife mitigation programs to be implemented or stricter energy efficiency targets to be pursued by Bonneville, those increased costs would also be reflected in the Tier 1 rates.

Tier 2 rates, which are charged for the portion of energy delivered by Bonneville to its preference customers that does not come from FCRPS generation, will reflect the net effect of climate change on the wholesale market prices. The average Tier 2 charges (40.86 mills/kWh in FY15) tend to be close to the wholesale market price because a portion of the energy Bonneville offers at those rates has been purchased in the wholesale market. The other portion comes from long-term power purchase agreements. The Northwest Power Act directs Bonneville to give priority to cost-effective conservation, renewables, and cogeneration options over other electricity generation sources in purchasing the power they will sell at Tier 2 rates.¹⁹ In deciding whether to purchase Tier 2 power from Bonneville or not, preference customers evaluate whether they could obtain better rates from alternative providers not subject to those restrictions or if they should develop their own generation resources.

Interactions between Bonneville and Wholesale Electricity Markets

Climate-related changes in the volume and timing of FCRPS generation matter for the extent of interactions between Bonneville and the wholesale markets. The projected volume of power bought and sold in the wholesale market will increase due to the larger seasonal mismatch between FCRPS generation and temperature-sensitive demand shown in Fig. 3.13. In addition, the increase in renewables throughout the West, partly due to policies aimed at mitigating climate change, is increasing the complexity of Bonneville's role as a balancing authority. In order to mitigate the costs of integrating renewables, Bonneville is considering increased coordination with adjacent balancing authorities. Both as a power marketer and balancing authority, the increased interactions with the wholesale market ultimately translates into costs, revenues, and savings that will be reflected in the rates Bonneville offers to its power and transmission customers.

Bonneville has experienced a decrease in the percentage of total sales that come from wholesale purchases during the 2001–2013 period. Except for a spike in 2010, which was a year with below-normal precipitation and streamflow in the Columbia River Basin, the percentage of total sales went from close to 20% to less than 10%. During that period, surplus power sales (MWh) were higher than replacement power purchases. Surplus power sales were highest in 2011, a year with above-normal precipitation.²⁰

The comparison between forecasted load and median simulated generation presented in Fig. 3.13 suggests replacement power purchases will increase in summer and surplus power sales will increase in late winter and spring. Thus, a situation in which the wholesale market price peaks in late winter and spring and is low in summer would be the most beneficial for Bonneville and its customers. However, the relationship between wholesale market prices and projected

¹⁹ <http://www.otecc.com/content/tier-2-facts>

²⁰ Within a given year, Bonneville will be a net seller in the wholesale market during some months and a net buyer during other months. Storage capacity constraints explain this outcome, at least partly. During the high-streamflow months, Bonneville has to generate more than its contracted commitments because it does not have enough reservoir space to store all the surplus water. During low-flow summer months, available water is typically not enough to cover its customers' demands.

hydropower generation reveals a conflicting (as opposed to a complementary) relationship, which is further explored in the following correlation analysis.

Fig. 3.14 displays the seasonality pattern of the most representative price for the PNW region: the Mid-Columbia price. From 2005 to 2012, the monthly average Mid-Columbia price followed a decreasing trend and typically reached its highest levels in December/January or July/August. FCRPS generation does not display a clear trend over the period considered here; however, it presents a clear seasonal pattern. Peaks in FCRPS generation, which correspond to periods during which Bonneville will have the most availability to make surplus power sales, tend to coincide with low-price periods and vice versa. The correlation between monthly prices and monthly generation for the period included in Fig. 3.14 is -0.41.

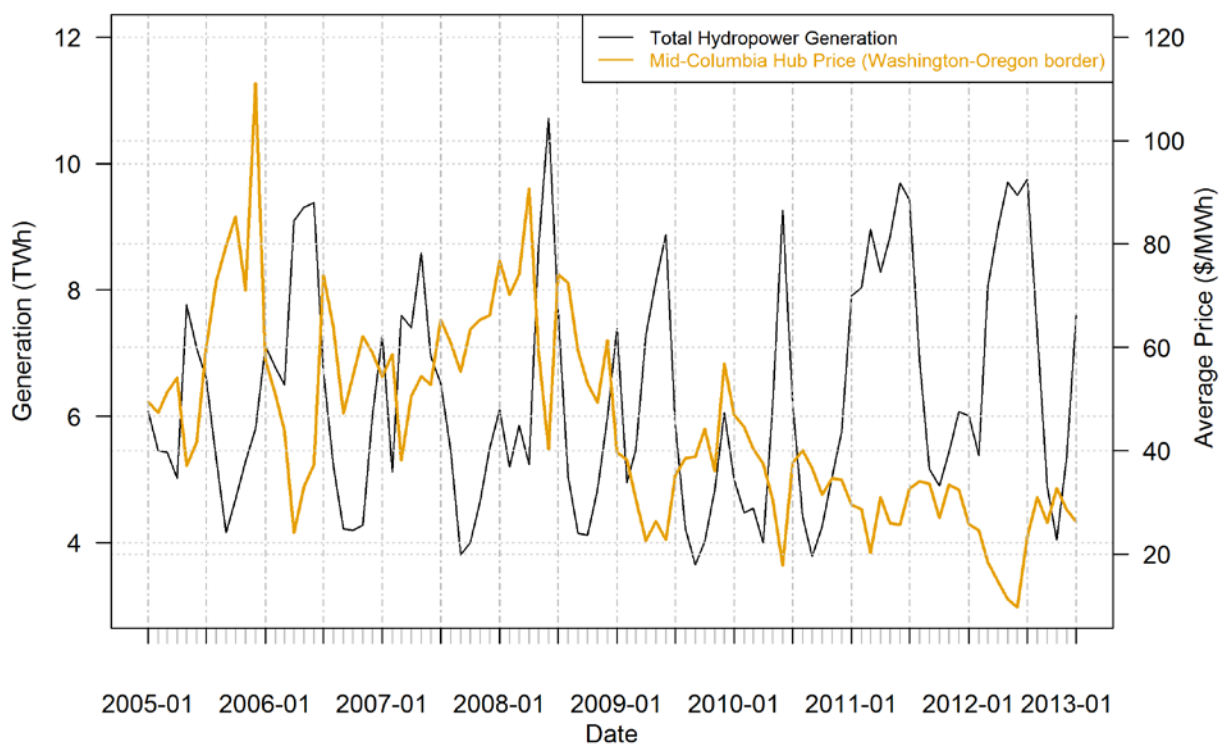


Fig. 3.14. Monthly generation at hydropower plants marketed by Bonneville versus regional monthly average wholesale price.

The generation mix in the PNW is consistent with the negative correlation observed in Fig. 3.14. The average fraction of in-state generation in Washington, Idaho, and Oregon that came from hydropower in the 2011–2013 period was 75%, 69%, and 64% respectively (Martínez et al. 2015). In such a hydropower-dominated system, it is logical to expect that price will be lowest at those times of year with more hydropower availability. From 2005 to 2012, the monthly average Mid-Columbia price has been lowest in the March-June period, which coincides with the highest streamflow months in the PNW. During the season of hydropower abundance, in hours with low demand and ample wind generation, oversupply situations have started to take place in recent years in the Bonneville balancing authority.

Bonneville has more than 5 GW of wind generation connected to its transmission system and expects an additional 3–4 GW by 2025.²¹ Increased variable renewables penetration results in more low-price events and episodes of energy surplus. This affects the value of surplus power sales by Bonneville, and it indirectly affects Tier 1 power rates negatively (NPCC 2011). Northwest Requirement Utilities estimates that Bonneville’s priority firm rate would be about 25% higher if the non-firm revenue were not available to offset costs. In addition, impacts of increased variable renewables penetration on the wholesale market price will affect Tier 2 rates.

During oversupply events, water can be spilled rather than passed through turbines, but only to the extent that it does not lead to levels of total dissolved gas above of the limits allowed by the Clean Water Act and the ESA, which harms fish and other aquatic species. Additional strategies to deal with oversupply range from implementing agreements with other hydropower operators to spill water and compensating them with energy from the FCRPS to reducing production at the (nuclear) Columbia Generating Station, among others. For situations in which all the strategies discussed above and the FCRPS spill are not sufficient, an oversupply management protocol is implemented through which Bonneville compensates non-hydro generators for reducing their generation.²² The costs of displacement are then allocated among all generators that were online during the oversupply event proportional to their scheduled generation. All in all, Bonneville’s wind integration services result in one more set of constraints to hydropower scheduling, and they reduce their flexibility to optimize revenue from surplus sales. Bonneville is exploring options to increase coordination with adjacent balance authorities in order to mitigate the costs associated with renewables integration.

The Northwest does not have a RTO or independent system operator performing centralized day-ahead and real-time dispatch.²³ However, day-ahead bilateral transactions using the Intercontinental Exchange are common.²⁴ Utilities in the region are members of the Northwest Power Pool (NWPP), which runs a reserve sharing program and ensures cooperation to achieve efficient operation and system reliability. The NWPP Management Committee is planning to start operating a centrally cleared 15-minute energy dispatch market in 2017–2018. By centralizing the dispatch of loads and generation resources across broader areas, the market would allow better management of fluctuations in generation from variable renewables, which is an important issue in the Bonneville balancing authority. The many competing priorities faced by the FCRPS limit its flexibility to manage sub-hourly fluctuations in wind and solar generation. Natural gas-fired generation is also capable of fast ramping and can be a great complement or substitute for hydropower in providing the operating reserves needed for renewables integration. However, only 9% of the installed capacity in the Bonneville balancing authority at the end of 2013 had natural gas as its primary source; by contrast, hydropower represented 65% of installed capacity, and 14% corresponded to land-based wind projects (EIA 2014a). Taking advantage of resource diversity in adjacent balancing authorities is one of the arguments for Bonneville to join

²¹ <http://www.bpa.gov/Projects/Initiatives/Wind/Pages/default.aspx>

²² Generators submit information on the cost of displacement to Bonneville. When the oversupply management protocol is applied, generators with the lowest cost are displaced first.

²³ Market operators perform centralized day-ahead dispatch by developing a schedule that determines which generators will start/stop and how much energy they will produce in each hour of the following day. The schedule is based on information submitted by each participating generator regarding availability, cost, and other physical constraints. The objective of the schedule is to meet projected load at the least cost possible. Real-time dispatch resolves the imbalances between projected load and committed generation resources within each hour.

²⁴ The Mid-Columbia price used in this section is the weighted average price associated to those transactions.

the NWPP proposed market. Bonneville is an active participant in the process of defining and designing this new market but has not yet made a definitive decision on whether it will participate in it or not.

Columbia River Treaty

Another source of uncertainty that will impact the volume and timing of hydropower generation that Bonneville can market stems from the Columbia River Treaty between the US and Canadian governments.²⁵ The treaty has no specified expiration date; however, it contains two important provisions that take effect on and after September 16, 2024. The first provision allows either Canada or the US to terminate the power provisions of the treaty with 10 years' written advance notice. The second provision transitions the coordinated and planned flood control operation with Canada to an obligation to operate any related storage in Canada when "called upon" by the US for flood control needs that cannot be adequately met by related U.S. facilities. These provisions could have large impacts on future power and flood control benefits. Formal negotiations between the two governments to modernize the Treaty have not started but are being discussed. The US Entity (i.e., BPA Administrator [chair] and the USACE Northwestern Division Engineer [member]) has put forward a Regional Recommendation saying that the modernization of the Treaty should "formalize, provide certainty, and build on the many ecosystem actions already undertaken through annual or seasonal mutual agreements between the countries, while also providing a net increase in U.S. power benefits based on the actual value of coordinated operations with Canada, preserving an acceptable level of flood risk to the people of the Basin, and continuing to recognize and implement the other authorized purposes in the Basin."²⁶

²⁵ The Columbia River Treaty was first signed in 1964 to alleviate flooding risk and to increase hydropower production. It entailed an agreement between the governments of Canada and the United States to build four more dams—three in Canada and one in the United States—along the Columbia River and to coordinate operations in the resulting system. In order to share the benefits equally between the two countries, the United States paid \$64.4 million dollars for Canada to operate a dedicated amount of storage for a coordinated and planned annual operation for flood control benefits in Canada and the United States. The 60-year period ends in 2024 and is replaced, under the Treaty, by an obligation to operate any related storage in Canada when "called upon" by the United States for flood control needs that cannot be adequately met by related US facilities. The United States does make an annual power payment to Canada. Under the terms of the Treaty, the United States shares with Canada the downstream power benefits resulting from the building and coordinated operation of the Canadian Treaty projects.

²⁶ <http://www.crt2014-2024review.gov/Files/Regional%20Recommendation%20Final,%2013%20DEC%202013.pdf>

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4 THE WESTERN REGION

Using the method described in Section 2, assessment results for federal hydropower plants marketed through Western Area Power Administration (WAPA or Western) are summarized in this section. Descriptions of the study area, background on hydropower operations, and marketing characteristics for Western are described in Section 4.1. Section 4.2 discusses the hydroclimate projections and reviews other recent studies within Western's operating territory. The potential impacts on federal hydropower generation and risks on federal hydropower marketing at Western facilities are discussed in the third subsection.

4.1 Regional Characteristics

4.1.1 Study Areas

Western is geographically the largest PMA, covering parts of 15 states ranging from California to the Great Plains and from the Mexican to the Canadian borders (Fig. 4.1). There are 55 federal hydropower plants in the Western region, with a total installed capacity of 10,180 MW and average annual generation of 29.5 TWh/year (Table 4.1, Appendix B) (NHAAP 2014). Western has more projects than Bonneville and is spread across a much larger service area, but it ranks second to Bonneville in terms of capacity and generation. Both USACE and Reclamation own and operate hydropower plants in this region. Based on power system and watershed boundaries, Western is subdivided into six study areas:

- Western Area 1 (WAPA-1) – Upper Missouri: the upper Missouri River and tributaries upstream of USACE's Gavins Point project
- Western Area 2 (WAPA-2) – Loveland Projects: 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) – Upper Colorado: the upper Colorado and upper Rio Grande River Basin
- Western Area 4 (WAPA-4) – Lower Colorado: the lower Colorado River Basin, including Reclamation's Hoover, Davis, and Parker Dams
- Western Area 5 (WAPA-5) – Rio Grande: the lower Rio Grande River, including two small projects operated by the IBWC
- Western Area 6 (WAPA-6) – California: the Central Valley of California (Trinity, Sacramento, American, Stanislaus, and San Joaquin river systems) and Truckee and lower Carson River systems

The first study area, WAPA-1, is the upper Missouri River in Montana, Wyoming, North Dakota, South Dakota, and a small part of Canada. The total drainage area of WAPA-1 is around 280,000 mi², with a small portion of this area located in Canada.

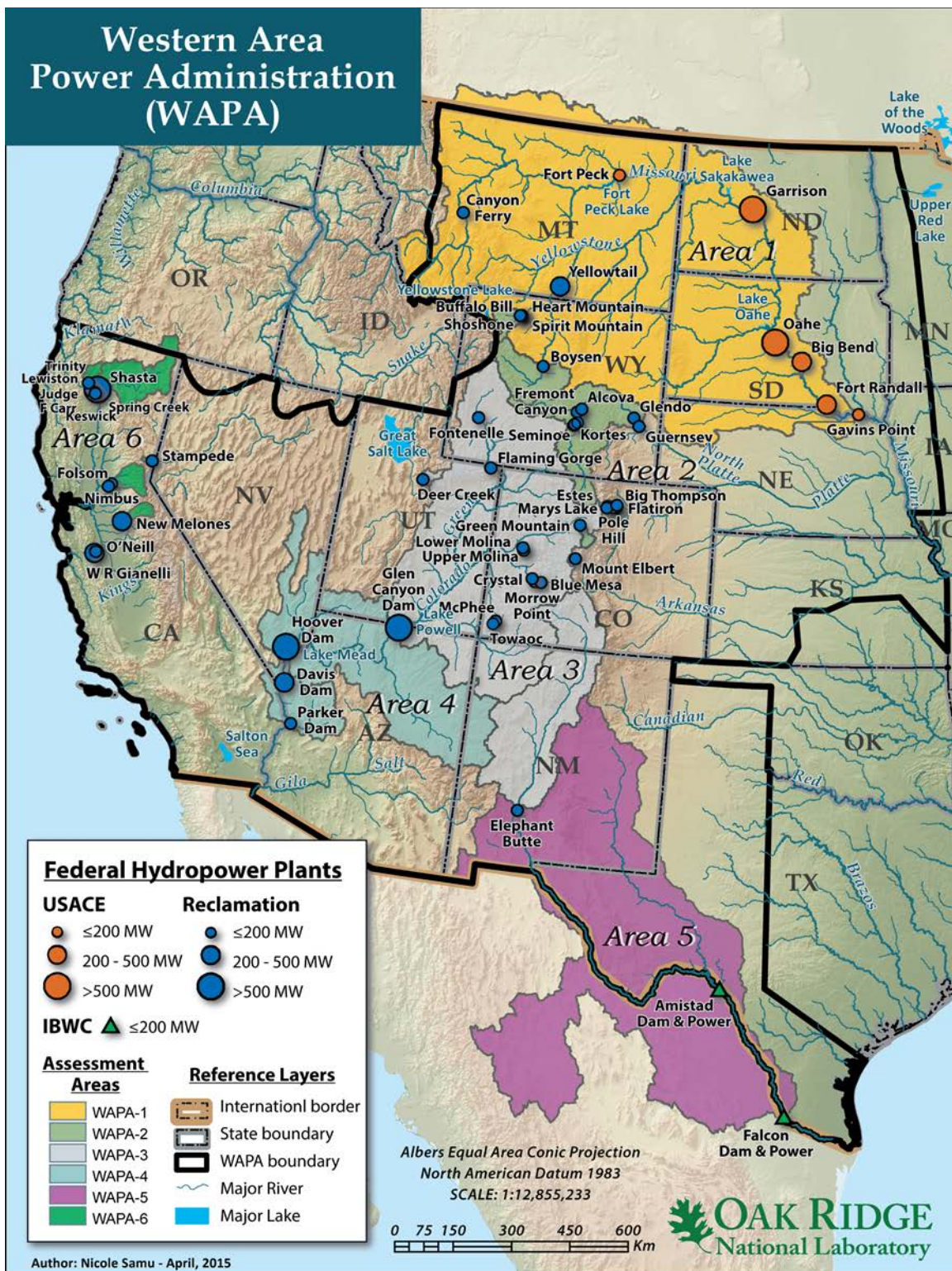


Fig. 4.1. Map of the federal hydropower plants and study areas WAPA 1-6 in the Western region.

Table 4.1. Summary of federal hydropower plants in the Western region

Area	Area name	Number of plants				Total installed capacity ^a (MW)	Average annual generation ^b (GWh/year)
		USACE	Reclamation	IBWC	Total		
WAPA-1	Upper Missouri	6	2	0	8	2,830	10,499.5
WAPA-2	Loveland Projects ^c	0	18	0	18	706	1,552.7
WAPA-3	Upper Colorado	0	12	0	12	1,822	6,034.5
WAPA-4	Lower Colorado	0	3	0	3	2,454	6,154.8
WAPA-5	Rio Grande	0	0	2	2	98	219.1
WAPA-6	California	0	12	0	12	2,270	5,001.9
Total		6	47	2	55	10,180	29,462.5

^a EIA 2013 total nameplate capacity, including both conventional hydro and pumped storage.

^b EIA and Reclamation average annual generation from 1970 to 2012, 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. Pilot Butte power plant was decommissioned in 2009 and hence is not included in this assessment.

This is the largest PMA study area and corresponds to the eastern division of the Pick-Sloan Missouri River system of multipurpose water projects. The topography is high plains and mountains, with a median elevation of 3,091 ft and a maximum elevation of 12,907 ft in the Rocky Mountains of western Montana. Land cover is primarily grassland (76%), plus cropland (14%) and evergreen broadleaf forest (6%).

The second study area, WAPA-2, consists of multiple smaller watersheds in the upper parts of the North Platte, South Platte, Bighorn, upper Arkansas, and upper Colorado Rivers. WAPA-2 corresponds to the Loveland Area Projects (LAPs), which include the Western Division of the Pick-Sloan Missouri River Program and the Fryingpan-Arkansas Project. The combined drainage area is 68,843 mi². In addition to the local flow, the Colorado-Big Thompson Project diverted more than 200,000 ac-ft of water each year into this area from west of the continental divide. The hydropower projects here are smaller, multipurpose Reclamation projects with primary purposes of water supply, not power. The topography is mountainous, with a median elevation of 6,880 ft and a maximum elevation of 14,035 ft. Land cover is grassland (76%), evergreen forest (14%), open scrubland (2%), and cropland (2%).

The third study area, WAPA-3, consists mostly of the upper Colorado River Basin west of the continental divide downstream to Reclamation's Glen Canyon Dam. The total drainage area is around 147,000 mi². 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, respectively. Land cover is a mix of grassland (47%), open scrubland (24%), evergreen forest (11%), and woody savanna (4%).

The fourth study area, WAPA-4, is the lower Colorado River Basin downstream of Glen Canyon Dam. The drainage area is 182,000 mi², 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, and maximum elevation is over 14,000 ft. Land cover is mostly open scrubland (69%), with minor amounts of grassland (14%), closed scrubland (10%), and woody savanna (3%).

The fifth study area, 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 mi², including the headwaters of the Rio Grande in New Mexico, and 71,000 mi² in Mexico. This is a much more arid area than other PMA study areas. Median and maximum elevations are 4,035 and 13,776 ft, respectively, which are still relatively high except for in the immediate area of the two hydropower projects. Most of the land cover is open scrubland (56%), with a mix of grassland (28%), closed scrubland (9%), and woody savanna (4%).

The sixth study area, 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, with a median of 4,754 ft. Land cover is mostly evergreen broadleaf forest (54%), plus woody savannas (20%), grassland (14%), and cropland (3%).

4.1.2 Federal Hydropower in the Western Region

Federal hydropower projects in the Western region are owned and operated by three different agencies: USACE, Reclamation, and the IBWC (Fig. 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 132.3 MW Gavins Point project to the 784 MW Oahe project. The two IBWC projects on the Rio Grande are part of multipurpose water development projects 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 list of the projects in this region is provided in Appendix B.

The average age of federal hydropower projects in the Western region is 45 years. The oldest Reclamation hydropower project in the Western region is Guersey, which began operation in 1927. The youngest Reclamation hydropower project in the region is the 4.5 MW Spirit Mountain hydropower plant that began operation in 1994. The aging of hydropower infrastructure (Sale 2011) in the Western and other PMA regions is a serious concern for both federal hydropower providers and their customers.

Since the resource of freshwater is fairly limited in the western US, hydropower generation is usually not the priority for multipurpose water management. The water demand for agricultural, municipal, and industrial uses must be met, and it has even greater importance than hydropower generation. As a result, 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 and navigation (USACE projects). Conflicts among competing water uses are common and continue in the Western region. In addition, there are serious concerns over the size and reliability of available water supply; if the climate becomes drier in this region in the

future, the amount of water resources, which is already inadequate for growing demands, may become even more scarce. The risks and impacts associated with current and future climate change to multiple water uses in major river basins throughout Western are discussed in Reclamation (2011). Further details on multipurpose water management issues in the Western region can also be found in Sale et al. (2012).

4.1.3 Power Marketing by Western

The same piece of legislation that created the DOE established Western as the youngest PMA in 1977.²⁷ A general description of what a PMA is and how it conducts its mission is presented in Section 1.2.2. Until Western's creation, Reclamation was in charge of marketing federal power in the West (excluding the FCRPS power, already marketed by Bonneville).

Western sells power from 55 hydropower projects (10,504 MW) and surplus power from the federal share (547 MW out of a total of 2,250 MW) of a coal-fired plant, the Navajo Generating Station. Western also owns more than 17,000 miles of high-voltage transmission lines, sells the transmission and ancillary services provided by that infrastructure, and operates four balancing authority areas. As a balancing authority, it is in charge of complying with grid reliability guidelines in these four areas. The role of Western as a balancing authority will be further discussed in Section 4.3.2.

The vast majority of Western's 688 customers are municipalities, cooperatives, federal or state agencies, irrigation districts, public utility districts, and Native American tribes, all of which are preference customers. Small resource pools are reserved for potential new preference customers in some Western projects. Western also sells to 19 IOUs and 35 power marketers. Most of the sales to power marketers come from the Central Valley (California Independent System Operator) and Pick-Sloan (MISO) projects, located within the footprint of organized wholesale markets where marketers conduct most of their transactions.

The variety of hydroclimatic zones across Western's footprint translates into a strong regional component in Western's marketing activities. Western has offices in each of its five marketing regions—Upper Great Plains, Rocky Mountains, Sierra Nevada, Desert Southwest, and Colorado River Storage Project. Power from each project is allocated among customers in that river basin based on separate marketing plans. Current marketing plans will expire between 2017 and 2028. The marketing plans propose the allocations of energy and, if available, capacity for each customer. Those allocations become obligations to serve the customer once the customer signs a contract with Western. The average duration of contracts is 20 years. Contract renegotiation is initiated well in advance of the expiration date and the new agreements are often signed years in advance of the start of power delivery. Renegotiation may be done through a power marketing initiative that extends the previous contracts without significant changes—used recently for LAPs in Colorado—or entail a full remarketing effort. An example of the latter is currently underway at the Boulder Canyon Project, which needs to implement the conditions established in the Hoover Power Allocation Act of 2011.

²⁷ The legislation was the Department of Energy Organization Act

Western offers four types of contracts corresponding to various lengths (long-term, short-term, and seasonal) and various degrees of energy availability (firm, non-firm). Firm power, which is only available for preference customers, is available 24 hours a day. In contrast, customers that purchase nonfirm power must show they have alternative resources to meet their load requirements at times when power from the federal hydro project will not be available. The firm energy allocations offered in long-term contracts are different for the summer and winter seasons. These seasonal differences reflect the annual hydrological cycle as well as the changes in water demands by other authorized project purposes throughout the year. For instance, more power will have to be allocated towards irrigation purposes in the summer than in the winter.

Rates differ significantly from project to project. The Falcon, Amistad, and Provo projects do not allocate capacity, only energy. At these projects, the total revenue requirement needed to repay the US Treasury each year is allocated across customers according to the fraction of energy they received. For the rest of the projects, the rates include a demand charge (per unit of capacity per month) and an energy rate. Table 4.2 summarizes the current rate schedules across Western's projects. Only the energy rates for the Parker Davis and Boulder Canyon projects have changed (11% increase and 17% decrease respectively) since those reported in the first 9505 report.

Table 4.2. Western FY15 rate schedule summary

Project	Demand charge (\$/kW-month)	Energy rate (mills/kWh)	Composite rate (mills/kWh)
Falcon and Amistad		Energy only	
Provo		Energy only	
Salt Lake Integrated Project	5.18	12.19	29.62
Parker Davis	2.07	4.72	9.44
Boulder Canyon		As available	
Central Valley		Energy only	
Loveland	3.92 (base) 1.51 (drought adder)	14.95 (base) 5.76 (drought adder)	41.42
Pick Sloan	4.90 (base) 2.75 (drought adder)	12.33 (base) 6.72 (drought adder)	33.25

Note: 1 mill = \$0.001

Managing imbalances between supply and demand caused by hydrologic variability or other factors is one of the key challenges that Western (and the other PMAs) encounter in their operations. The Loveland and Pick-Sloan projects include capacity and energy components in their rates (drought adders) to recover costs associated with Western's replacement power purchases during drought situations. Similarly, a cost recovery charge is used in the Salt Lake Integrated Project to collect adequate revenues for the purchase of replacement power. The cost recovery charge is updated every fiscal year. Customers can avoid paying this charge if they agree to a reduced volume of firm energy deliveries.

As a federal power marketer, Western manages imbalances between firm energy contracted with customers and available generation at federal hydropower projects. As a balancing authority, Western also has to manage discrepancies between total generation and total load at the control area level. Western uses a variety of mechanisms to address these imbalances depending on how

far ahead they can be forecasted and how long they are expected to last. When generation turns out to be greater than what Western has contractually committed to deliver, it will offer the surplus power on the wholesale market. On the other hand, if power generated is insufficient to meet contractual obligations, Western will buy replacement power. To cover deficits that arise due to short-term weather and system conditions, spot purchases are often the only option. When the deficit is foreseen years in advance, Western can buy futures or negotiate a power purchase agreement to acquire electricity from a generation resource on a longer-term basis. If changes in hydrology or river operations are predicted to continue long term, it is possible to modify the quantities allocated in the long-term, firm power contracts but customers must be given at least five-year notice.

4.2 Future Climate in the Western Region

This section presents the projections of the future hydroclimate conditions in the Western region. Based on the hydroclimate simulation described in Section 2, the projections of mean annual, spring, summer, fall, and winter temperature, precipitation, runoff and evapotranspiration are summarized in terms of change from baseline period (1966–2005) to near-term future (2010–2030) and midterm future (2031–2050) periods for each of the six Western study areas.

4.2.1 Regional Climate Projections

The projected annual temperature for baseline (1966–2005) and future periods (2011–2030 in near-term and 2031–2050 in midterm) are illustrated in Fig. 4.2, with gray lines representing projections made by different climate models, green line representing the multimodel median, and black line showing the 1981–2012 Daymet temperature observation. The corresponding multimodel probability distributions in the baseline and future periods are compared in the right panel. A two-sample Kolmogorov-Smirnov test at the 5% significance level is used to determine whether the difference between baseline and future periods is statistically significant. The main use of this type of interannual plot is to visualize the range of variability and trend made by each model and to evaluate if the projected trend and variability is consistent with historic observation. Since climate models are not meant to reconstruct the exact timing of the historic interannual and decadal variability, the model runs are not expected to fully follow the historic interannual values. The same condition applies when interpreting similar interannual plots of precipitation, runoff, and generation.

In all six assessment areas (WAPA-1 to -6), the increasing trend in the ensemble median annual temperature is similar to the observed trends in the historic time period, although with a larger intermodel variability (Fig. 4.2). The large intermodel variability is projected and provides a good example illustrating why a multimodel ensemble approach must be used to understand the overall picture. In the future, temperatures across all Western areas are projected to continue to increase. Moreover, comparison of the probability distributions of multimodel mean annual temperature for the future and baseline time periods also show a statistically significant warm shift for the 2011–2050 time period in all WAPA areas (Fig. 4.2).

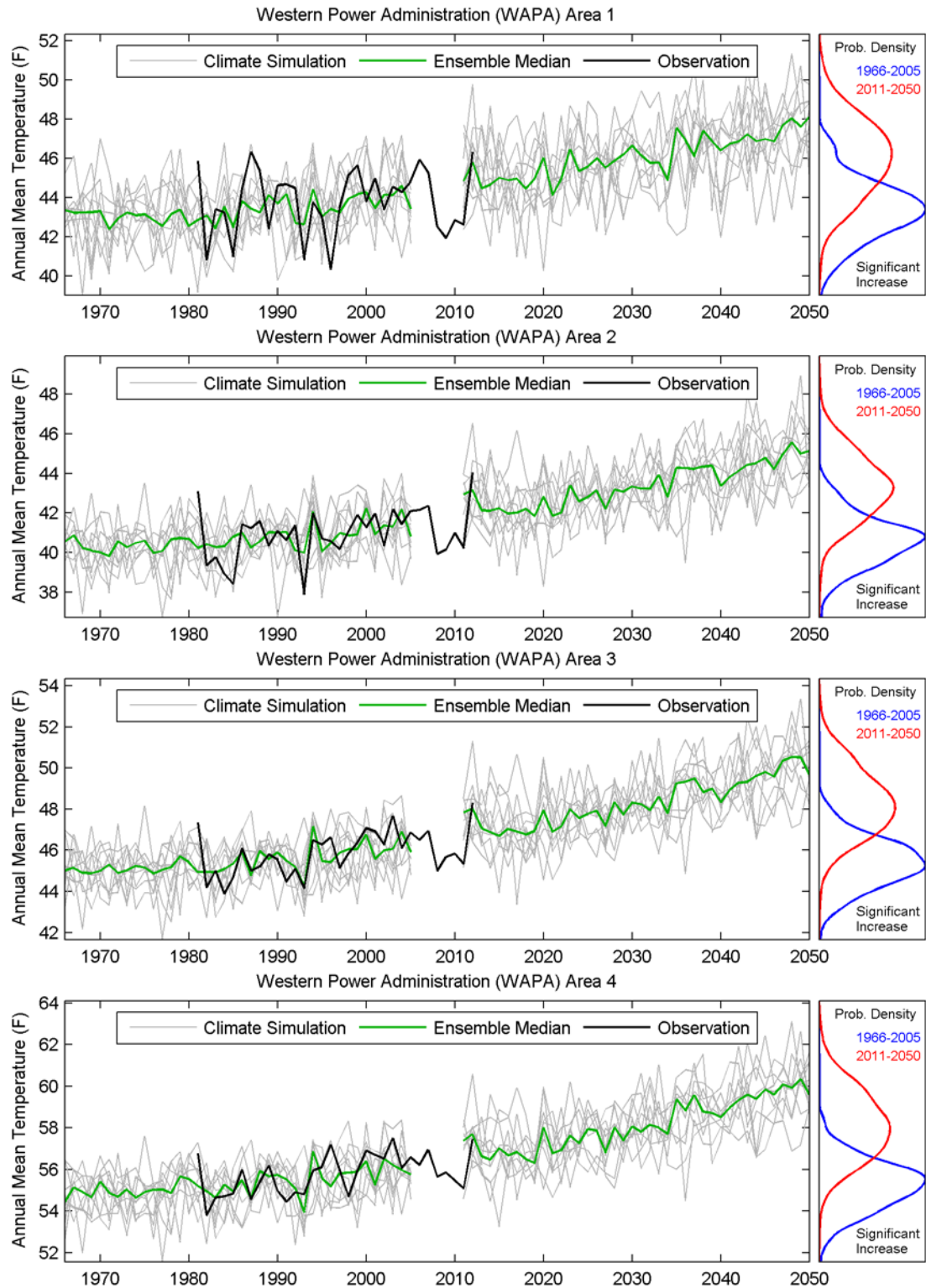


Fig. 4.2. Projected annual mean temperature in the Western region.

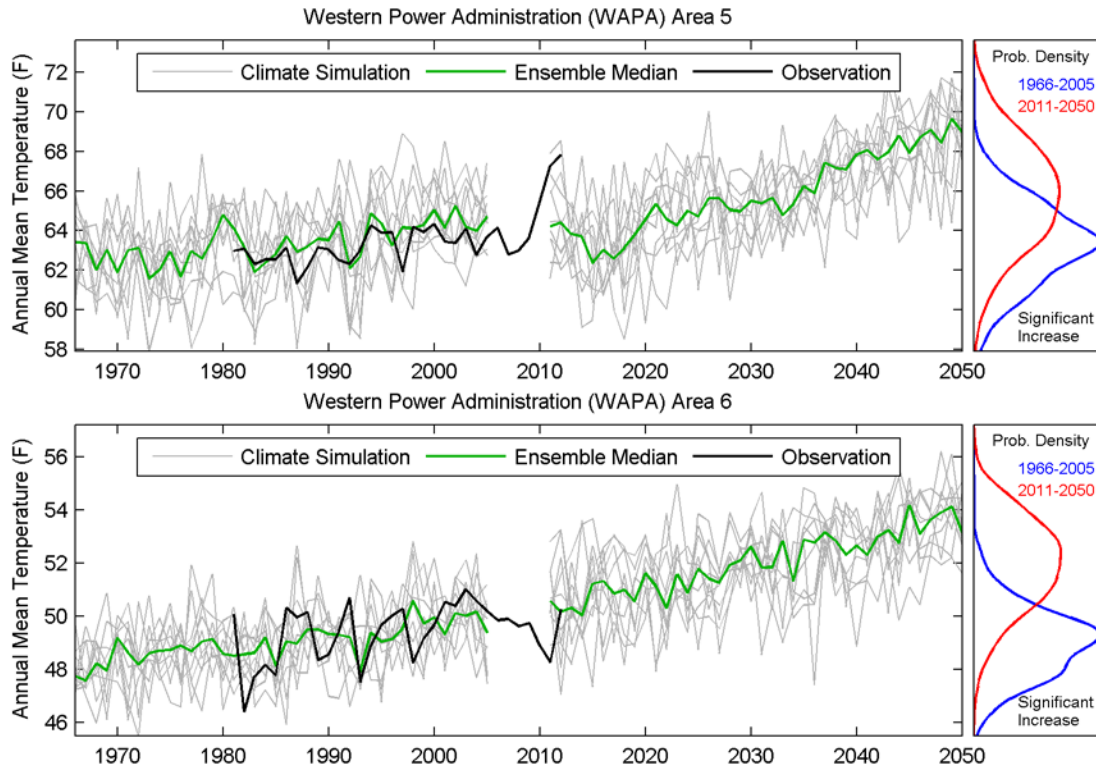


Fig.4.2. Projected annual mean temperature in the Western region (cont).

The annual and seasonal changes of temperature are further summarized in Fig. 4.3. Change is defined as the degree difference (F) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of box indicating the 25th and 75th percentiles, and the whiskers extending to the lowest/highest models. In all Western assessment areas, a greater increase is projected in the summer (July–August), with a relatively larger increase in the midterm future period (Fig. 4.3 and Appendix D). Multimodel median annual temperature for Western is projected to increase by about 1.5 °F to 2.5 °F in the near-term future and 3.0 °F to 4.5 °F in the midterm future periods (Fig. 4.3 and Appendix D). Spring and summer warming (~ 4 °F in the midterm) is projected to exceed that of all other seasons in all Western areas (as in many parts of the US). However, for WAPA-5, all seasons are projected to warm slightly more than 4 °F at the most. While the increase in temperature may not have a strong influence directly on annual runoff (see sensitivity analysis in Section 2.4.4) and consequently projected hydropower, it causes earlier snowmelt and a shifted seasonal pattern in runoff that will be discussed in the next subsection. This temperature-triggered earlier snowmelt effect is among one of the more certain findings in future climate projections.

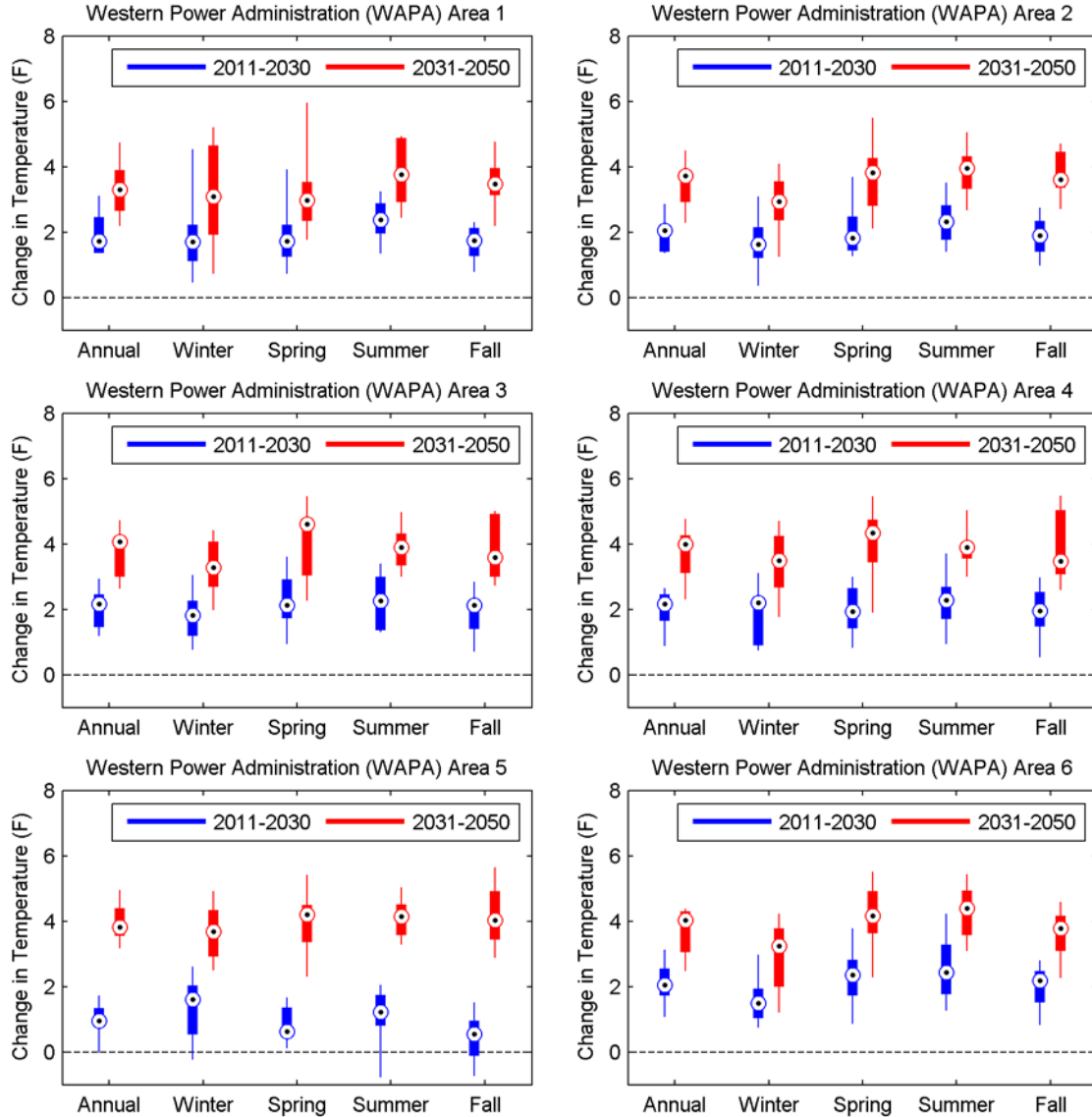


Fig. 4.3. Projected change of annual and seasonal mean temperature in the Western region.

Unlike temperature projections, the annual precipitation projections do not show obvious long-term trends (Fig. 4.4). However, the probability distributions of mean annual total precipitation in the future time period show a statistically significant increase in precipitation for WAPA-1 and WAPA-2. In other areas of Western (WAPA-3, -4, -5, and -6), the change in mean annual precipitation is not significant, but interannual variability is much larger in the future time periods as shown by flatter probability distribution in Fig. 4.4.

The annual and seasonal changes of precipitation are summarized in Fig. 4.5. Despite the statistically insignificant trend in future annual precipitation in four of six Western study areas, future projections do show a consistent increasing trend in wet season precipitation across all Western study areas (Fig. 4.5 and Appendix E). In the near-term future (2011–2030) period, increasing winter precipitation is projected across all Western areas except in WAPA-5, where precipitation is projected to decrease in the wintertime (Fig. 4.5 and Appendix E). For WAPA-4

and WAPA-6, precipitation is projected to decrease in spring and summer, whereas in other areas the change in summer precipitation is small or there is nearly no change (in terms of multimodel median). Mean annual precipitation projections for most areas show statistically insignificant trends in both future periods; however, WAPA-1 (the upper Missouri) and WAPA-2 (lower Missouri) does show projections nearing +5% in both periods with respect to the baseline period (Fig. 4.5 and Appendix E).

In all of Western's study areas, the more important signals include (1) increases in temperature in all seasons, and (2) increases in winter precipitation (except for WAPA-5). The impact of these changes will have important implications for future water availability in the Western region as discussed in Section 4.2.2.

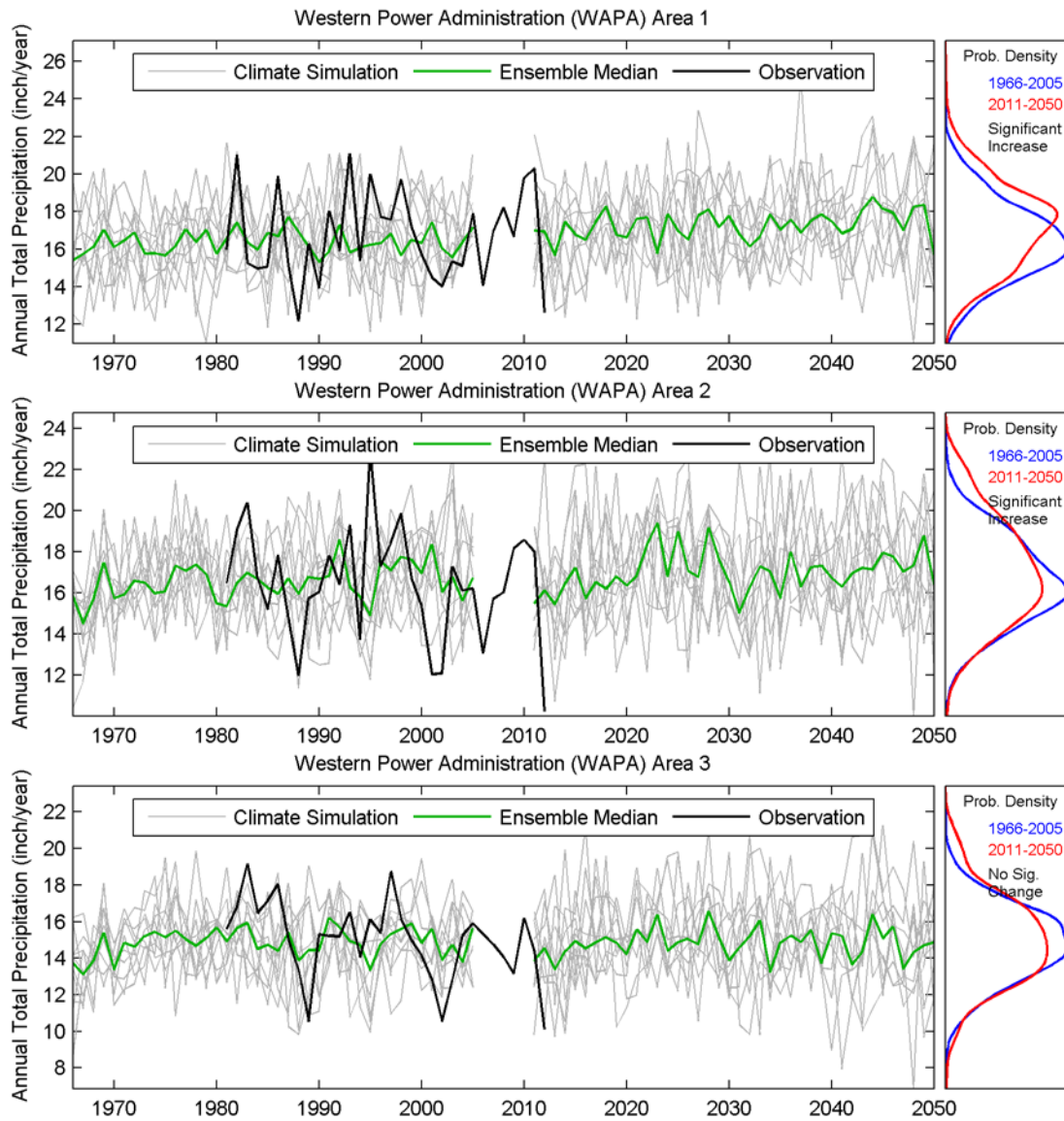


Fig. 4.4. Projected annual total precipitation in the Western region.

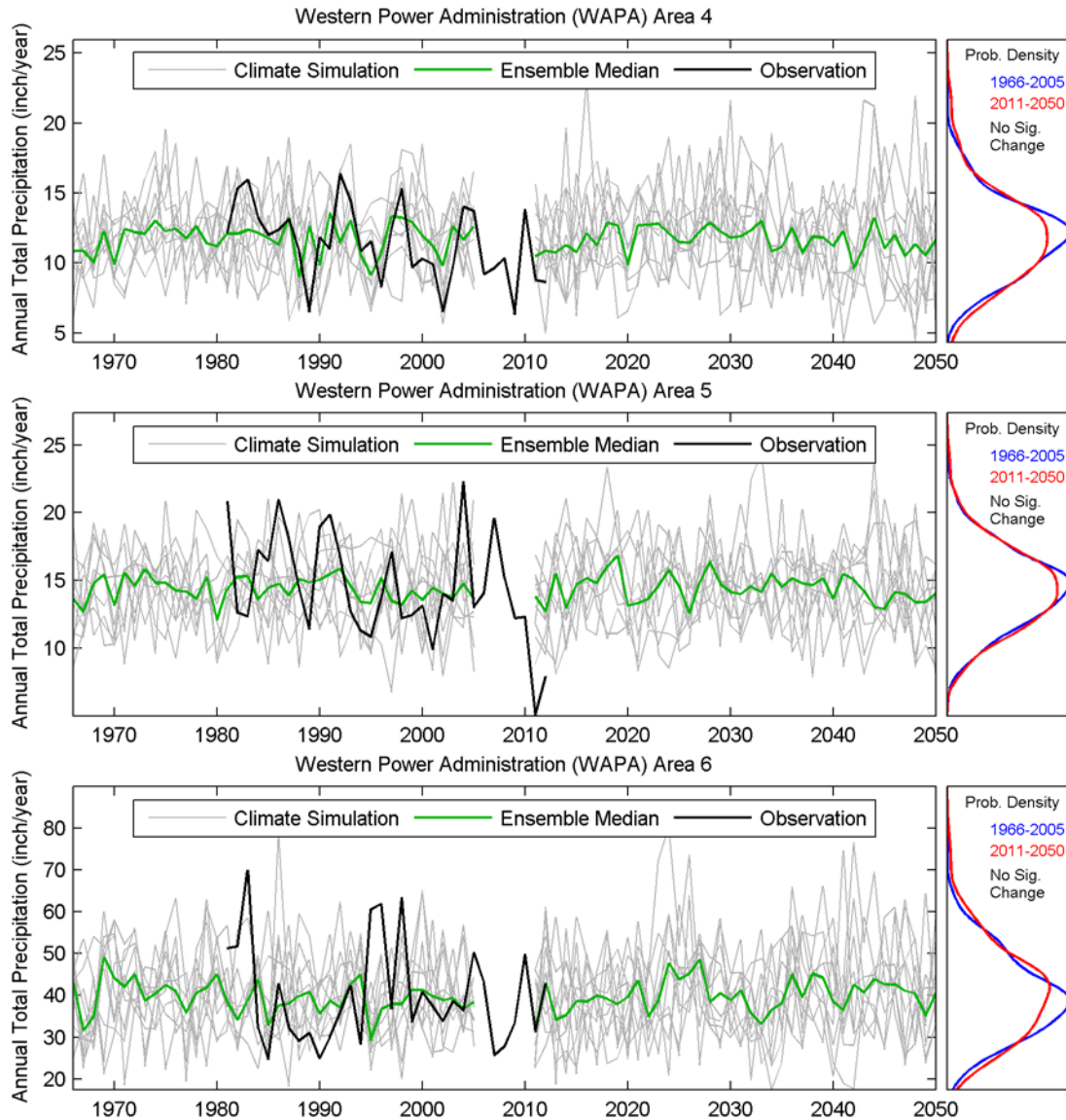


Fig. 4.4 Projected annual total precipitation in the Western region (cont).

4.2.2 Regional Hydrological Projections

The hydrologic response to projected climate changes is illustrated in Fig. 4.6, Fig. 4.7, and Fig. 4.8. Fig. 4.6 shows the projected evolution of annual total runoff for the ten downscaled projections averaged spatially over each Western assessment area for both baseline and future periods. The gray lines show the annual total runoff from ten downscaled climate models for both 1966–2005 baseline and 2011–2050 future periods, and the green line indicates the multimodel median. The 1981–2012 historical observation from WaterWatch is shown as a black line for comparison. The corresponding multimodel probability distributions in the baseline and future periods are compared in the right panel. A two-sample Kolmogorov-Smirnov test at the 5% significance level is used to test if the difference between baseline and future periods is statistically significant. Similar to the projected precipitation variability (Fig. 4.4), it would be difficult to distinguish consistent long-term climate change signals from near-term and midterm

climate projections with the high natural variability in runoff. However, the probability distributions of mean annual runoff in the future time period show a statistically significant increase in runoff for WAPA-1, WAPA-4 and WAPA-5 areas, but in other areas of WAPA, the change in projected runoff is not statistically significant.

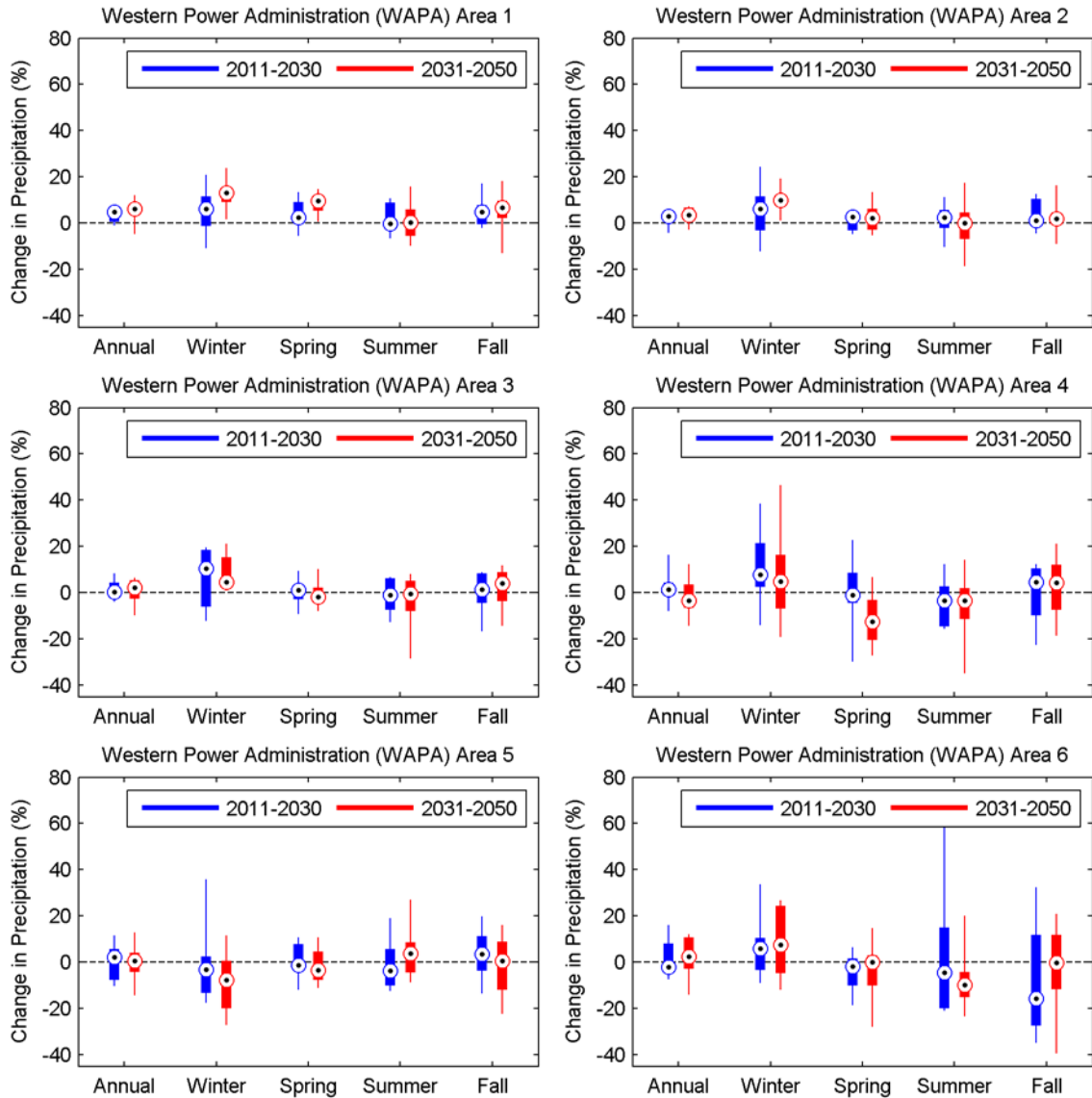


Fig. 4.5. Projected change of annual and seasonal total precipitation in the Western region.

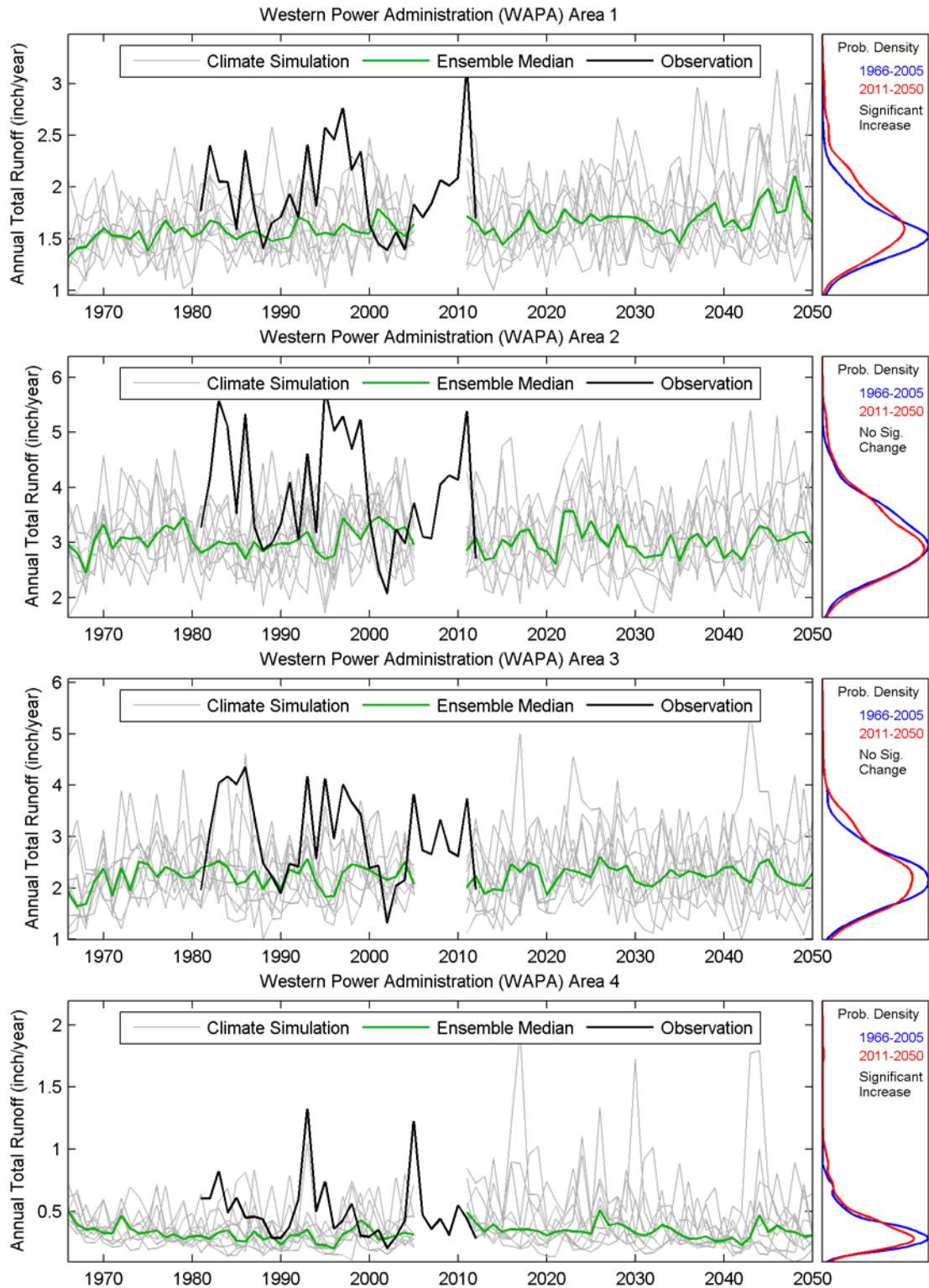


Fig. 4.6. Projected annual total runoff in the Western region.

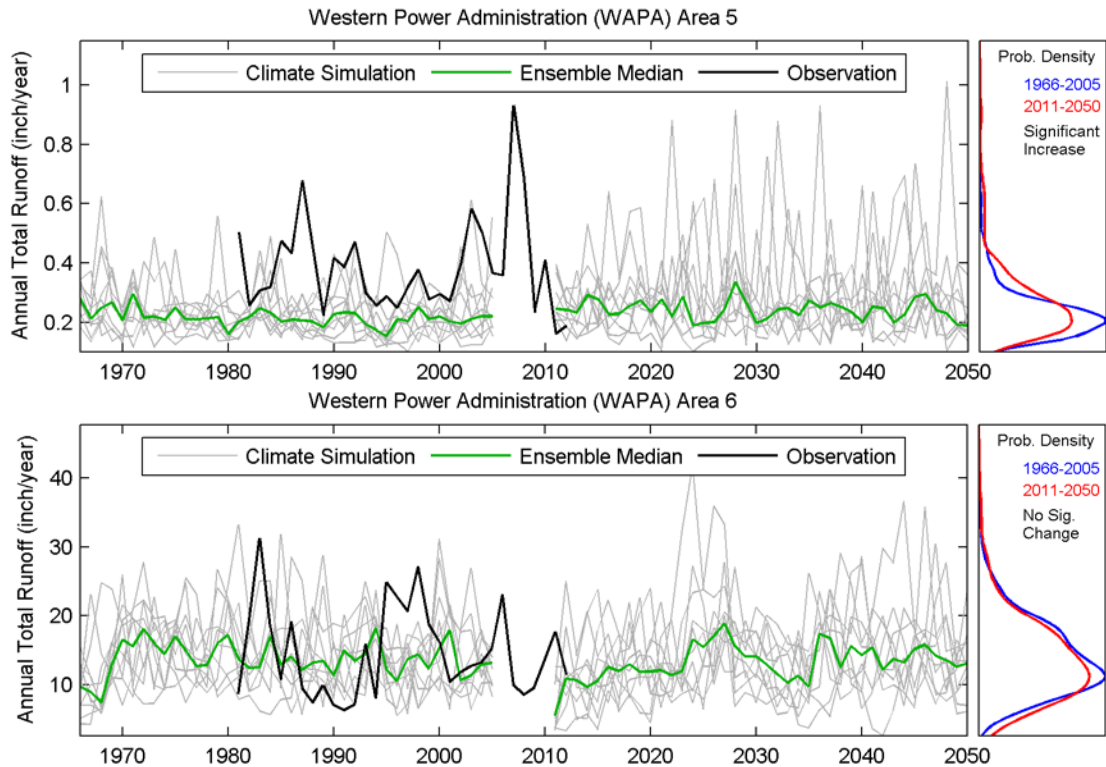


Fig. 4.6. Projected annual total runoff in the Western region (cont).

On a seasonal basis, the combined effect of increasing temperature and changes in precipitation on the total runoff can be clearly seen in Fig. 4.7 and in the monthly hydrograph of projected 90th, 50th and 10th percentile of monthly runoff in Appendix F. The strongest change projected in total runoff over Western for both future periods is the increase in spring and decrease in the summertime runoff, particularly in WAPA-1 through WAPA-3 (Fig. 4.7). Increases are projected to be more modest in the winter and fall seasons in these areas. Runoff is projected to increase across all seasons in WAPA-4, with the highest increase in winter and spring. In the WAPA-5 area (Rio Grande), an increase in total runoff is projected in all seasons with a greater increase in summer, while WAPA-6 shows decreasing runoff in all seasons for both future periods, except in the winter where a modest increase is projected during the midterm future period. Despite the fact that in the WAPA-4, WAPA-5 and WAPA-6 areas, runoff projections show quite a large spread among the ensembles for both future periods, the projected increases in runoff in WAPA-4 and WAPA-5 and decreases in WAPA-6 are notable in all seasons.

Consistent with increases in winter runoff in WAPA-4 and WAPA-6, Fig. 4.8 shows that increases in winter evapotranspiration are projected in these study areas. These changes appear to be primarily driven by increasing temperatures and available soil moisture from increased precipitation and snowmelt in winter and spring seasons. However, decreased runoff combined with low summer precipitation produces a summer decrease in soil moisture, resulting in no change to a decrease in summer evapotranspiration, as shown in Fig. 4.8.

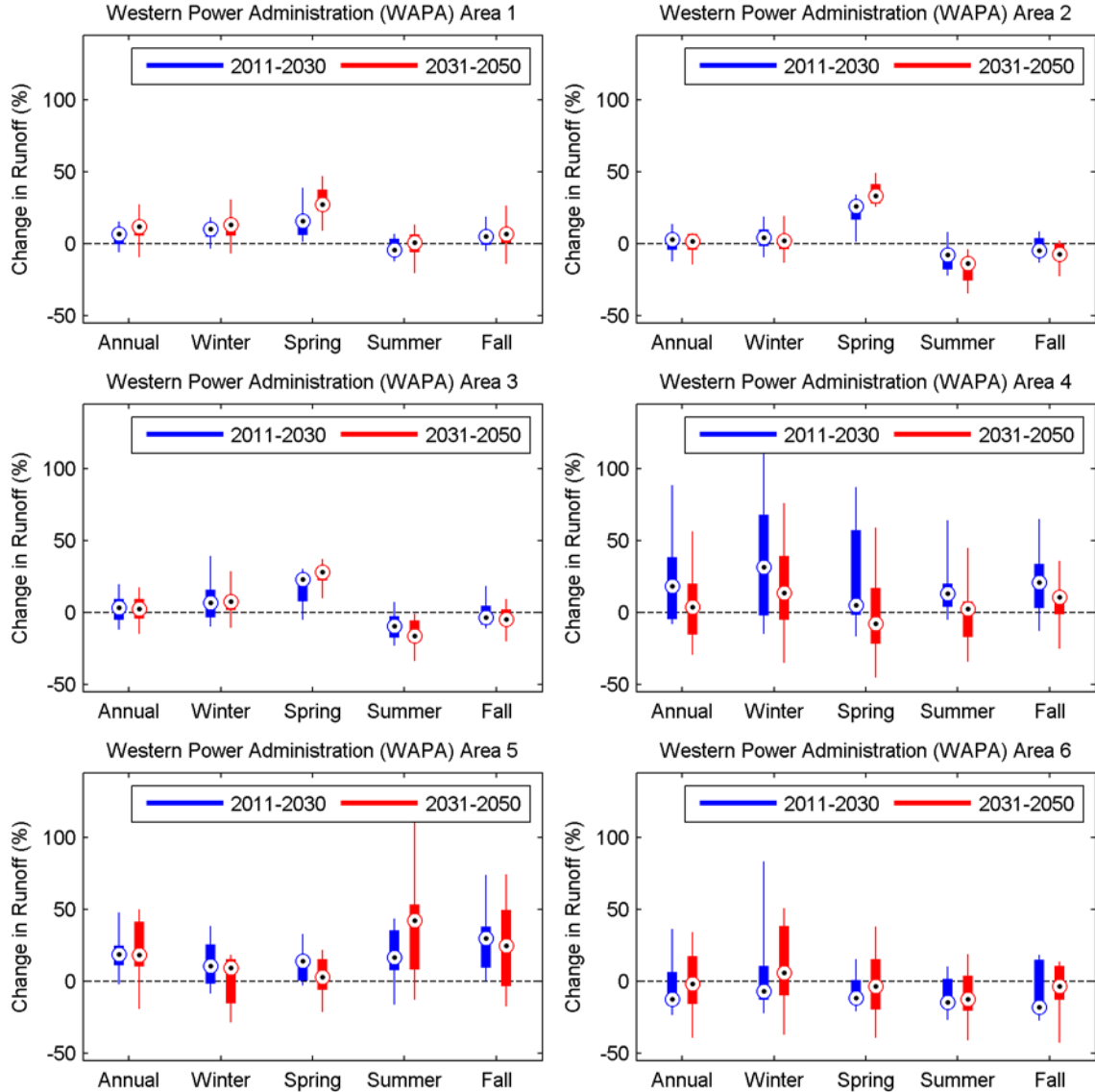


Fig. 4.7. Projected change of annual and seasonal total runoff in the Western region.

These changes in runoff and evapotranspiration are likely associated with a decrease in ensemble median April 1st SWE and maximum SWE (Fig. 4.9a, b), particularly in the WAPA-3 and WAPA-4 areas (upper and lower Colorado). A reduction in snow-covered days is also projected in these areas (Fig. 4.9c). The change is defined as the percentage difference (%) for the April 1st SWE and the maximum SWE and absolute difference (future – baseline) for the annual snow-covered days of the future period (2011–2050) compared to the 1966–2005 baseline period. All grid cells in which long-term (i.e., average across the 1980–2012 control run) April 1st SWE was greater than 5 mm were identified and used as a spatial filter to summarize the simulated April 1st SWE, the snow-covered days, and the annual maximum SWE for each model and for both baseline and future periods. However, in WAPA-1 (upper Missouri), the change in annual maximum SWE and snow-covered days is projected to increase (Fig. 4.9b, c); this change can be attributed to an increase in winter precipitation leading to stronger snowstorms in the Northern Missouri region. Such changes in snow hydrology combined with changes in the runoff regime

suggest that more water is available to runoff earlier in spring, and it may result in drier conditions in the summer over some areas of Western as shown earlier in Fig. 4.7.

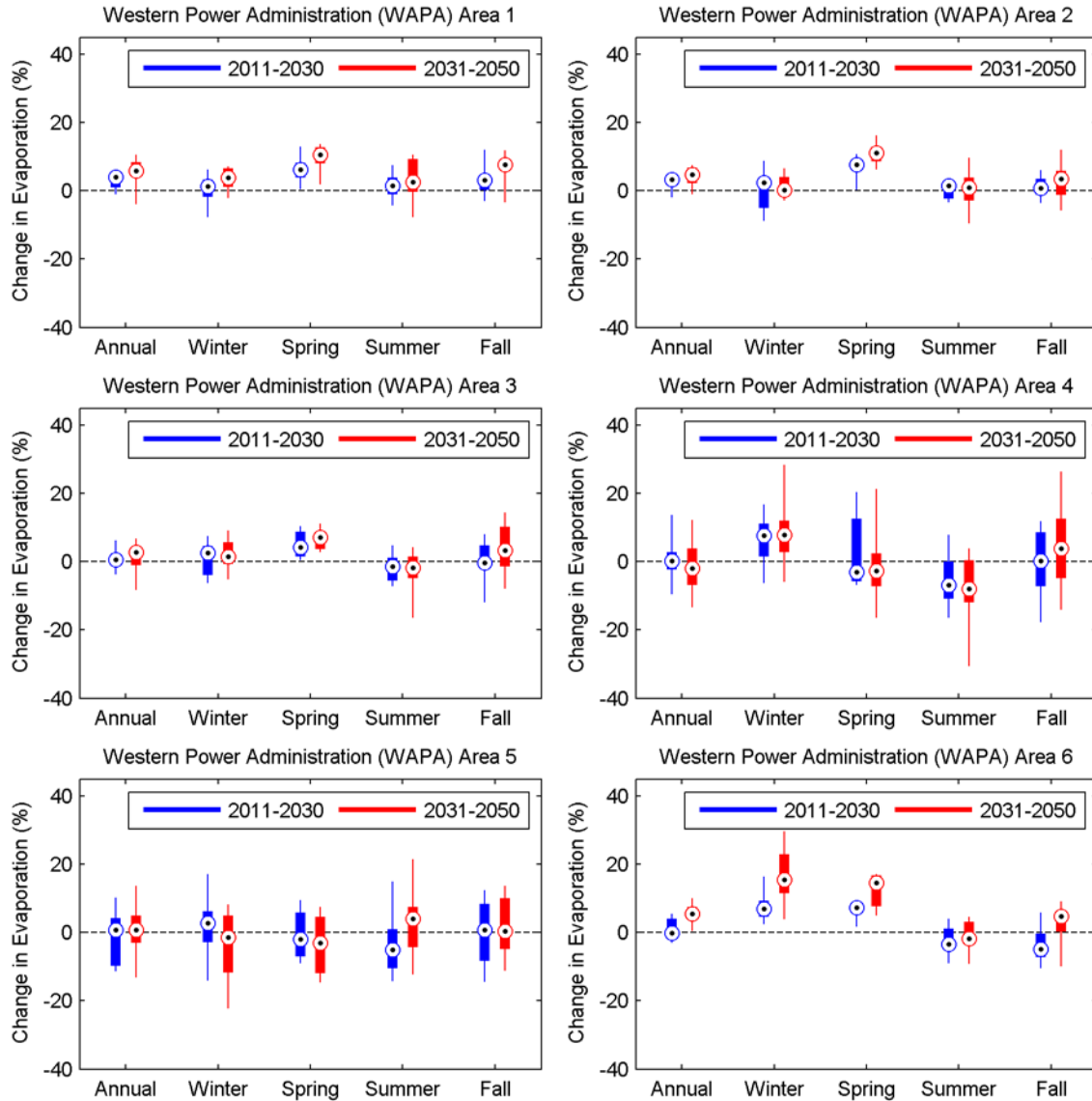


Fig. 4.8. Projected change of annual and seasonal total evapotranspiration in the Western region.

Additional extremes-related analysis is shown in Fig. 4.10, which presents future changes in ensemble median high runoff (i.e., 95th percentile of daily runoff) and median low runoff (i.e., 5th percentile of running 7-day average runoff) for both future projection periods in the Western region. Increases in high runoff are projected in both future time periods (Fig. 4.10a and b), suggesting the potential of more extreme runoff events, particularly in WAPA-1 through WAPA-3. However, a decrease in high runoff is projected in WAPA-4 to WAPA-6. Similarly, increases in low runoff are also projected in most areas of Western, with some places in WAPA-3 to WAPA-6 showing decreasing change in low runoff (Fig. 4.10c and d). This suggests the possibility of more extreme runoff events in the western regions; however the projected change is more variable throughout Western, with areas to the north showing increased, high, and low

runoff, and southern areas showing decreased high runoff with more spatial variability for the low runoff conditions. These results suggest the possibility of more frequent flood and drought events and may present a future challenge for water managers.

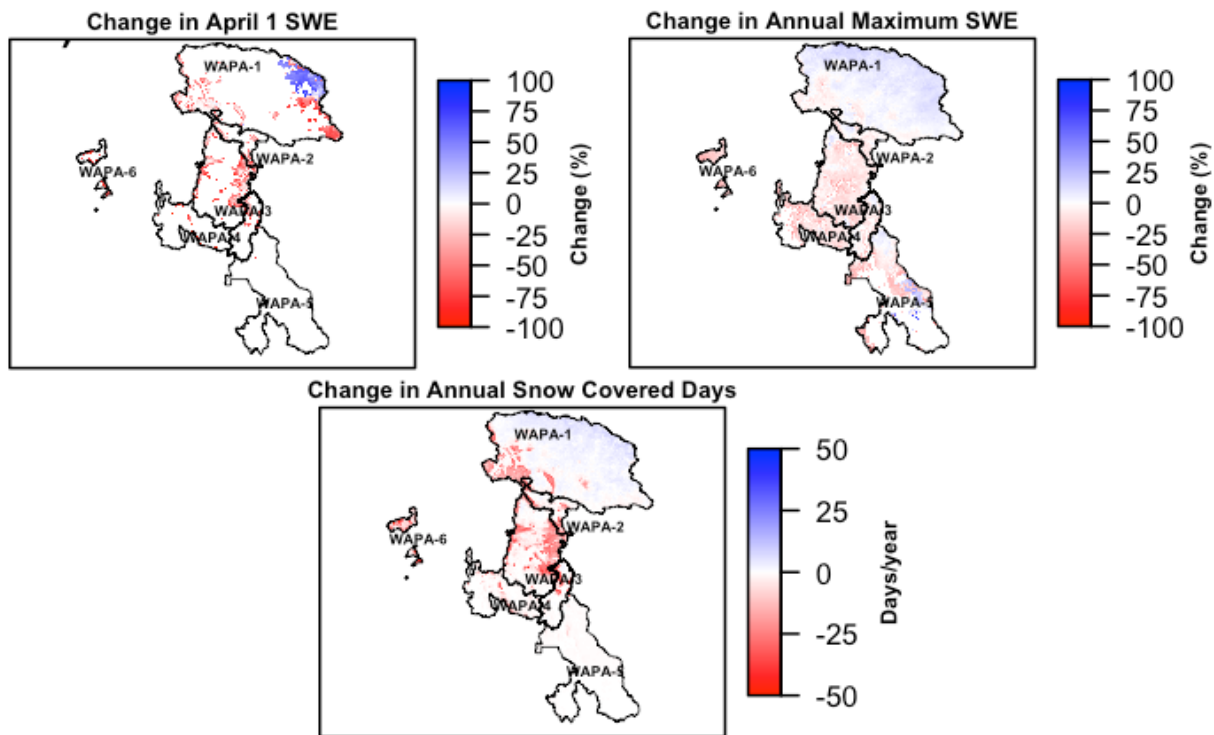


Fig. 4.9. Spatial distribution of multimodel ensemble median change in (a) April 1st SWE, (b) annual maximum SWE, and (c) annual snow-covered days in the Western region.

The main findings of future climate projections over Western for 2011–2050 include:

- Multimodel median annual temperature for Western is projected to increase by about 1.5 °F to 2.5 °F in the near-term future and 3.0 °F to 4.5 °F in the midterm future periods compared with the 1966–2005 baseline. For most of Western, the summer season is projected to warm the most, except for WAPA-5 which shows increase in temperature at a slightly more than 4 °F in all seasons.
- Projected changes in precipitation present a mixed picture. Projections of mean annual precipitation show statistically significant increases in WAPA-1 and WAPA-2, driven mainly by increases in winter and spring precipitation. Decreases in summer precipitation over the California Central Valley (WAPA-6) are possible for the midterm.
- Many Western areas are projected to experience changes in seasonal or annual runoff. Annual total runoff is projected to increase significantly in WAPA-1, WAPA-4 and WAPA-5 areas. Other important signals in runoff changes include: (1) Increase in spring runoff and decrease in summer runoff, which is more evident in WAPA-2 and WAPA-3. These changes appear to be caused by earlier snowmelt (due to warmer temperature) during winter and spring. (2) Despite that very little change is projected in precipitation in the WAPA-5 area, the percentage increase in total runoff is large. This indicates that small changes in

precipitation can be enhanced into strong runoff response in this area. (3) In WAPA-6, most of the annual/seasonal changes in runoff are projected to decrease, driven largely by decrease in spring, summer, and fall precipitation.

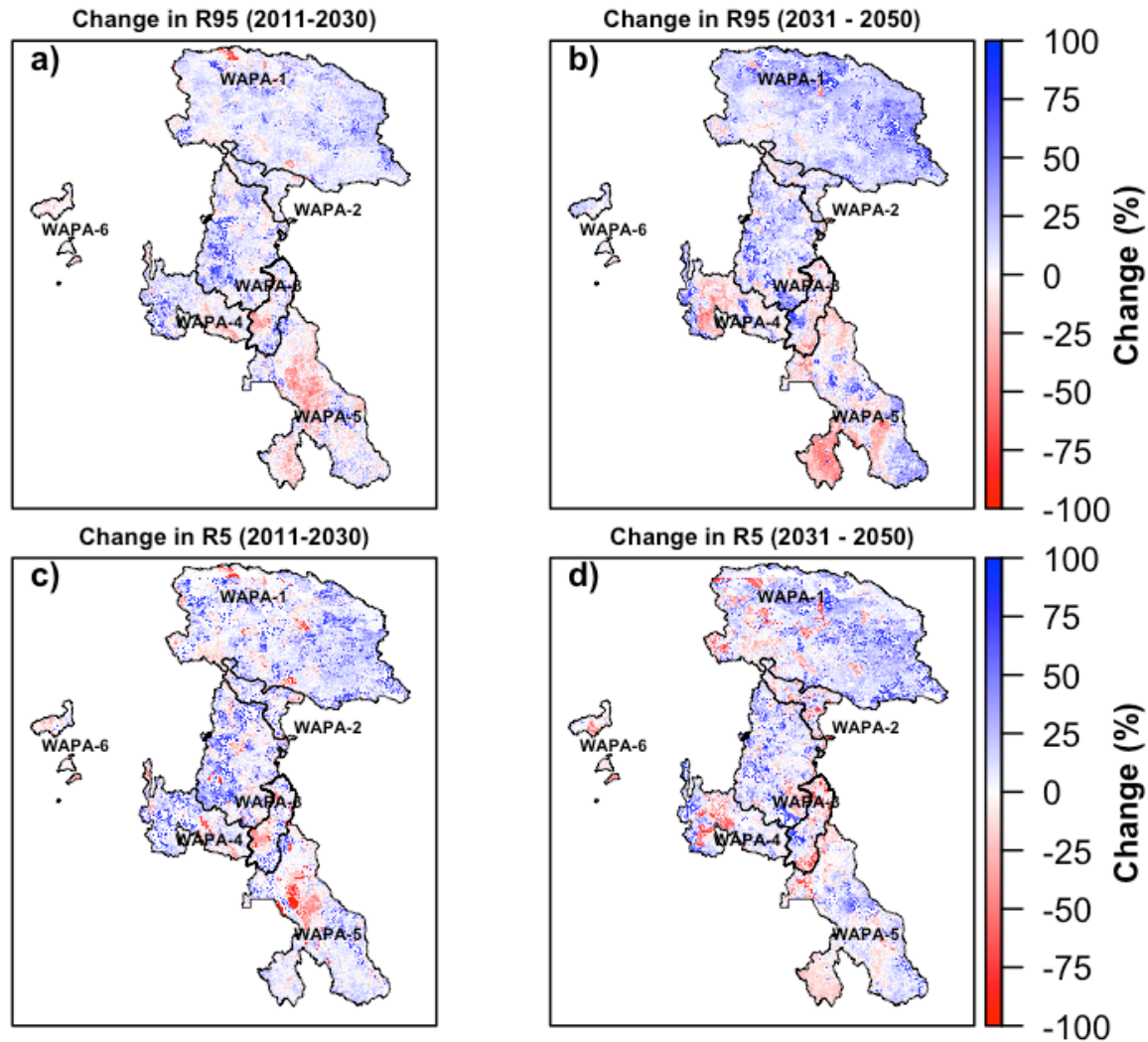


Fig. 4.10. Spatial distribution of multimodel ensemble median percentage change in (a) high runoff in 2011–2030, (b) high runoff in 2031–2050, (c) low runoff in 2011–2030, and (d) low runoff in 2031–2050 time periods in the Western region.

4.2.3 Comparison with Other Climate Studies in the Region

The projections of temperature, precipitation, and runoff for Western in this assessment for 2011–2050 period cannot be directly compared with projections from other available studies (as discussed below) owing to several factors, such as differences in spatial domain, differences in GHG emissions scenarios in the models and the different spans of the baseline and projection periods. Nonetheless, some qualitative statements and comparisons can be made between this assessment and other studies.

In general, results of recent studies indicate a strong consensus regarding a significant warming trend throughout 21st century based on GCM and/or RCM projections (Hagemann et al. 2013, Liu et al. 2013, Melillo et al. 2014, Scherer and Diffenbaugh 2014, Elguindi and Grundstein 2013, Kunkel et al. 2010, Ojima et al. 2013). The Climate Change Assessment for the third NCA (Kunkel et al. 2013d) indicates temperature increase in the northern Great Plain regions by about 4.4 °F by the end of midcentury under the A2 (high emission) scenario based on CMIP3 projections. For the southwest regions, in particular the WAPA-5 area, another analysis conducted by Kunkel et al. (2013c) also shows an average annual temperature increase of 7.5 °F – 8.5 °F by the end of the 21st century based on CMIP3 projection under A2 scenarios. The projected increase in temperature is about 5.5–6.0 °F for the southwest regions according to the NARCCAP projections. These results from past studies are generally consistent with this assessment results shown in Fig. 4.3.

Unlike temperature projections, past studies generally have a low consensus on the direction and magnitude of precipitation change in the Western region. For example, a number of studies projected a decrease in precipitation, particularly in the Colorado region (Cayan et al. 2013, Seager and Vecchi 2010, Christensen and Lettenmaier 2007, Jerla et al. 2012). Rasmussen et al. (2014) shows an increase in wintertime precipitation in Colorado headwaters based on a high-resolution (4 km) dynamical downscaled simulation using the WRF model, which is consistent with this assessment that also projects an increase in wintertime precipitation both in WAPA-3 and WAPA-4 areas (upper and lower Colorado regions). Similarly, in other assessment areas such as in WAPA-5 (Rio Grande region), a general decreasing change in precipitation was found by most previous studies. Hagemann et al. (2013) projected a decrease in precipitation for Rio Grande region based on GCM outputs, whereas Liu et al. (2013) shows a decrease in winter and spring precipitation but increases in summer and fall precipitation. Melillo et al. (2014) reported a decline in wintertime precipitation at the end of 21st century in this region as described in the third Climate Change Assessment report. In addition, a study by Reclamation also indicates a gradual decrease in precipitation for the Rio Grande Basin (Llewellyn and Vaddey 2013). The precipitation projections from this assessment also show a decrease in winter and spring precipitation but project a slight increase in summer for the midterm period for WAPA-5 (see Fig. 4.5). In contrast, for the Missouri regions (WAPA-1 and WAPA-2), most previous studies projected a relatively wetter future climate than drier (Kunkel et al. 2013d, Reclamation 2012). These results are also consistent with changes in precipitation projected by this assessment for the Missouri regions.

Regarding the runoff projections, changes in runoff reported by other studies are spatially contrasted. For example, most recent studies conducted for the Colorado region primarily show decreases in the projected flow by end of 21st century, but these projections are highly uncertain due to considerable variability in the future climate projections. Harding et al. (2012) uses the downscaled translations of 112 CMIP3 projections to investigate uncertainties in future projected flows for the Colorado basin. This study found that 25 to 35% of ensemble runs show no change or increases in future flows, while the remaining ensemble runs projected a decrease in flows by end of 21st century. Similarly, another recent study by Cayan et al. (2013) uses sixteen model ensemble runs to evaluate projected changes in annual runoff, finding an overall decrease in the annual median runoff in the 21st century for the southwest regions; however, the strong decreases are found in the April–July season, which they attributed to a decline in the April 1st SWE. The projections of summer (June–August) runoff in this assessment also show strong decreases on

the order of 20–30% for the midterm, but they also show strong increases in the winter and spring runoff (Fig. 4.7, except the midterm spring runoff in WAPA-4). Cayan et al. (2013) also project a decrease in snowpack for the southwestern US, including the Colorado Region, which closely corresponds to this assessment's results (see Fig. 4.9). Additionally, 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 this assessment) to produce runoff projections. This study shows a slight increase in the projected spring runoff followed by a larger decrease in summer month. Projected seasonal runoff changes from this assessment also show similar types of change for the WAPA-3 area. An attempt to reconcile the various studies for the Colorado River was made by Vano et al. (2014).

Many recent studies also projected drier conditions in the Rio Grande regions (WAPA-5) (Hagemann et al. 2013, Gangopadhyay and Pruitt 2011, Hurd and Coonrod 2012). A recent study by Reclamation also projects a decrease in mean annual flows, where most flows are projected to decrease in the summer (Llewellyn and Vaddey 2013). Similarly, Georgakakos et al. (2014) also shows a decrease in both winter and summer flows based on CMIP3 outputs. In contrast to these studies, this assessment shows an increase in runoff in all seasons for both future time periods. The highest increases in runoff occur in the summer (see Fig. 4.7), despite the projected decrease in seasonal precipitation (Fig. 4.5). Ashfaq et al. (2010) found that in arid regions, the increase in runoff events is associated mostly with an increase in heavy precipitation (as shown in Fig. 4.10), even with the projected decrease in total precipitation. In the WAPA-6 areas, a study by Cloern et al. (2011) on California's San Francisco Bay-Delta-River System suggested runoff decreases consistent with this assessment's results (Fig. 4.7). It should also be noted that this assessment's results are for the midcentury and use dynamically downscaled projections to force the hydrologic model. Thus the results described in this assessment are not directly comparable with these studies. Some further comparison of this assessment's projections and the Brekke et al. (2013) CMIP5 projections is illustrated in Appendix C.

4.3 Climate Effects on Federal Hydropower in the Western Region

This subsection discusses how the projected hydroclimate change may affect federal hydropower generation in the Western region. The projected change in annual and seasonal generation is presented in Section 4.3.1. The potential risk to hydropower marketing is discussed in Section 4.3.2.

4.3.1 Projections of Hydropower Generation

Using the WRES model described in Section 2.5, projections of monthly generation and watershed storage in the Western region are calculated for each of the ten downscaled climate models. Projections based on multimodel ensembles are summarized in terms of the mean annual and seasonal changes (i.e., spring, summer, fall, and winter) for the near-term future (2011–2030) and midterm future (2031–2050) periods as compared to the baseline period (1966–2005).

The interannual variability of annual hydropower generation for the baseline and future periods is shown in Fig. 4.11, with gray lines representing projections made by different climate models, the green line representing the multimodel median, and the black line showing the 1981–2012 historic observation from EIA and PMAs. The corresponding multimodel probability

distributions in the baseline and future periods are compared in the right panel. A two-sample Kolmogorov-Smirnov test at the 5% significance level is used to determine if the difference between baseline and future periods is statistically significant.

The annual and seasonal change of hydropower generation is further summarized in Fig. 4.12. The change in Fig. 4.12 is defined as the percentage difference (%) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of box indicating the 25th and 75th percentiles, and whiskers extending to the lowest/highest models. The monthly multimodel 10th, 50th, and 90th percentiles of generation and watershed storage are shown in Appendices H and I for further illustration.

It should be noted that the WRES model is developed and calibrated using the 1981–2012 hydropower, hydrology, and meteorology data, and hence it can only simulate how a current and stable hydropower system (i.e., without a significant change in installed capacity) may react to changes in meteorological and hydrologic inputs. This corresponds to one special feature of the US federal hydropower system: since the 1970s, there has been limited change in the total installed capacity (Kao et al. 2015). This lack of change in the federal hydropower system resulted in a rather stationary generation of data that enabled the development of simplified hydropower models such as EBHOM (Madani and Lund 2009 and 2010) and WRES. With WRES' model limitations in mind, the simulated 1966–1980 generation represents how a current (i.e., 1981–2012) hydropower system would respond to the simulated 1966–1980 runoff and precipitation. Therefore, the simulated 1966–1980 generation will not be able to reflect the expanded capacity during that period. It will only serve as a baseline for comparison to future climate projection in this study. It can also be noticed that the control simulations capture the stronger decadal variability in some regions. This supports the current understanding that the decadal variability has yet to be well simulated in the current climate models.

Since the federal hydropower plants in the Western region are spread across a variety of geographical regions with distinct climate features, the future hydropower projection results across all Western study areas are not fully consistent. In WAPA-1, future hydropower generation is projected to increase across all seasons in both future periods (Fig. 4.12). In terms of the multimodel median, annual hydropower is projected to increase around +3% in the near-term future and +10% in the midterm future. The largest increase is projected in spring (+8% / +10% in two future periods). An increasing trend in the annual hydropower generation for WAPA-1 is projected in Fig. 4.11. The increase in hydropower generation in WAPA-1 is mainly caused by the increasing precipitation (Section 4.2.1) in the upper Missouri River basin. This wet trend has been suggested by various models and studies and was also reported in the previous assessment (Sale et al. 2012).

Both WAPA-2 and WAPA-3 are in the snowmelt-dominated upper Colorado River region and have similar trends. In terms of annual generation, the change is relatively small (less than +3%) and does not have a significant increasing trend in annual generation. However, similar to the areas in the Bonneville region, the seasonal change is fairly large and can be greater than +20% in spring. This significant increase in spring is accompanied by reduction of generation in other seasons. The shift in seasonal generation is likely caused by earlier snowmelt (triggered by increasing air temperature). The direction of change is similar to the change of runoff (Fig. 4.7),

but at a smaller magnitude (e.g., spring midterm runoff is +25% while generation is +21%). The smaller rate of change is projected since the storage capacity of the hydropower system may provide a buffer to absorb some future runoff variability.

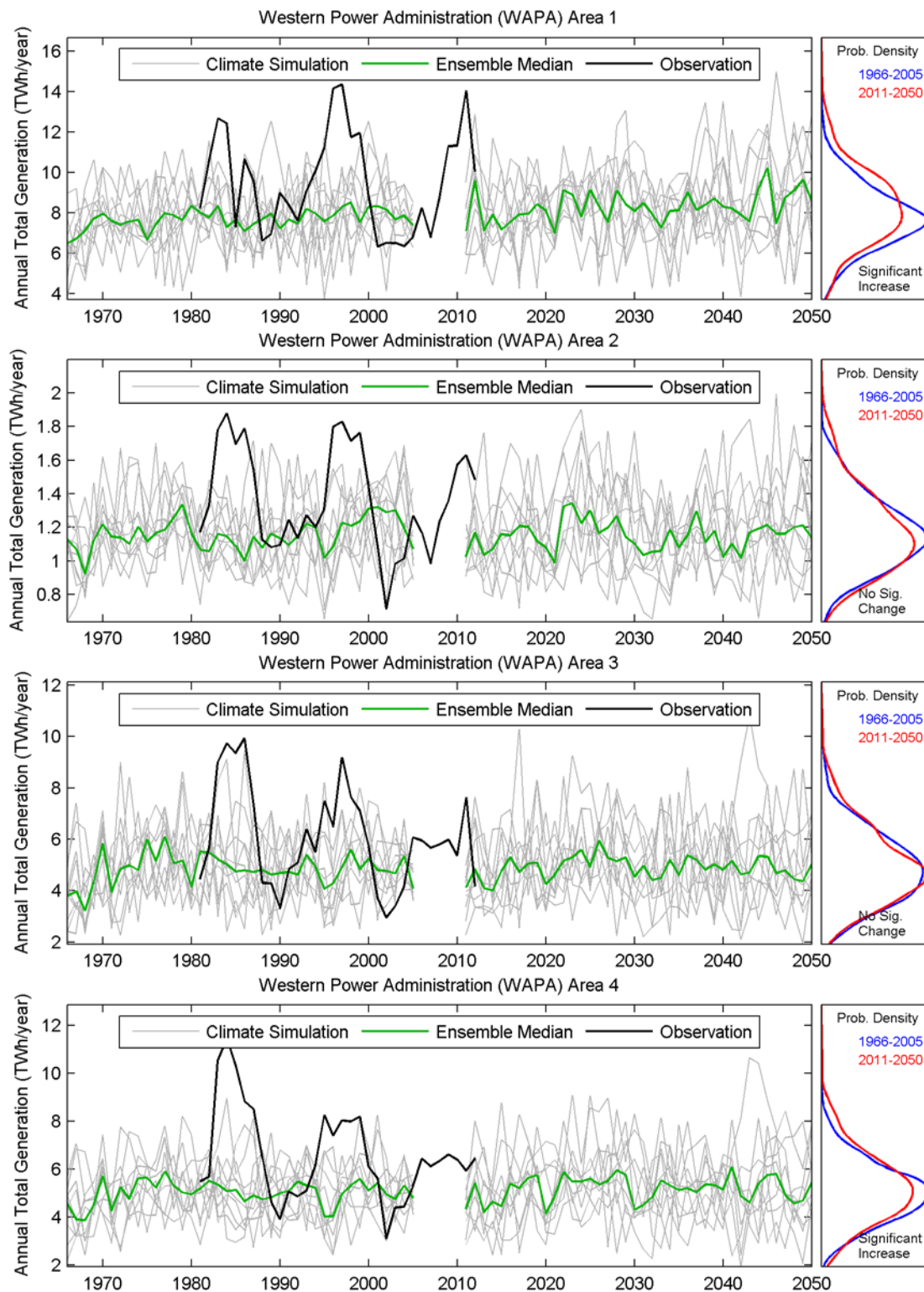


Fig. 4.11. Projected annual total generation in the Western region.

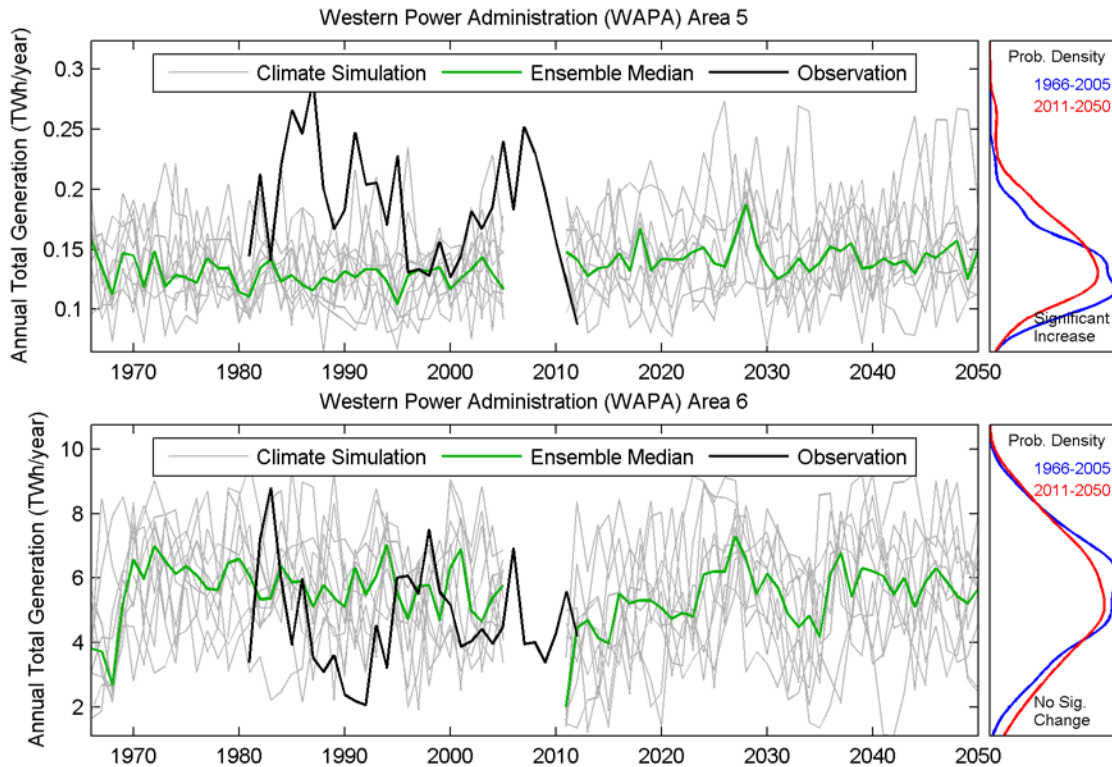


Fig. 4.11. Projected annual total generation in the Western region (cont).

The results of WAPA-4 in the lower Colorado River region show +7% increase in terms of multimodel median in annual generation. The most noticeable feature is the large multimodel spread in winter and fall, which is partially caused by the more diverse precipitation projections among ten selected climate models (Fig. 4.5). Compared to the large rate of change in runoff (Fig. 4.7), the change of seasonal generation is in a much smaller magnitude. This could be owing to the large storage capacity provided by Hoover Dam and Lake Mead in this study area. The storage capacity greatly helps reduce the large variation of future runoff (Fig. 4.7).

In WAPA-5, the annual generation in terms of multimodal median is projected to increase around +9% and +11% in two future periods (Fig. 4.12). A larger increase is projected in winter and spring, while a lower increase is projected in summer and fall. Nevertheless, it should be noted that WAPA-5 is one of the two areas with the lower WRES modeling performance (Section 2.5). Therefore, the seasonal hydropower projection made for this study area is subject to a much larger uncertainty.

Similar to the lower precipitation and runoff projection made by the ten selected climate models in the near-term future period, the annual hydropower generation in WAPA-6 shows a larger decrease in the near-term future (-13% decrease in terms of multimodel median) but recovers in the midterm future (-1% decrease). The models made diverse projections for winter generation, ranging from -25% to +30% in the near-term future and -48% to +30% in the midterm future (Fig. 4.12). While the rate of change is the largest in comparison to the other WAPA study areas, it is already at a smaller magnitude when compared to the projected change of future runoff (Fig. 4.7). The interannual variability made by the models is consistent with the observed ones (Fig. 4.11) with no significant trend.

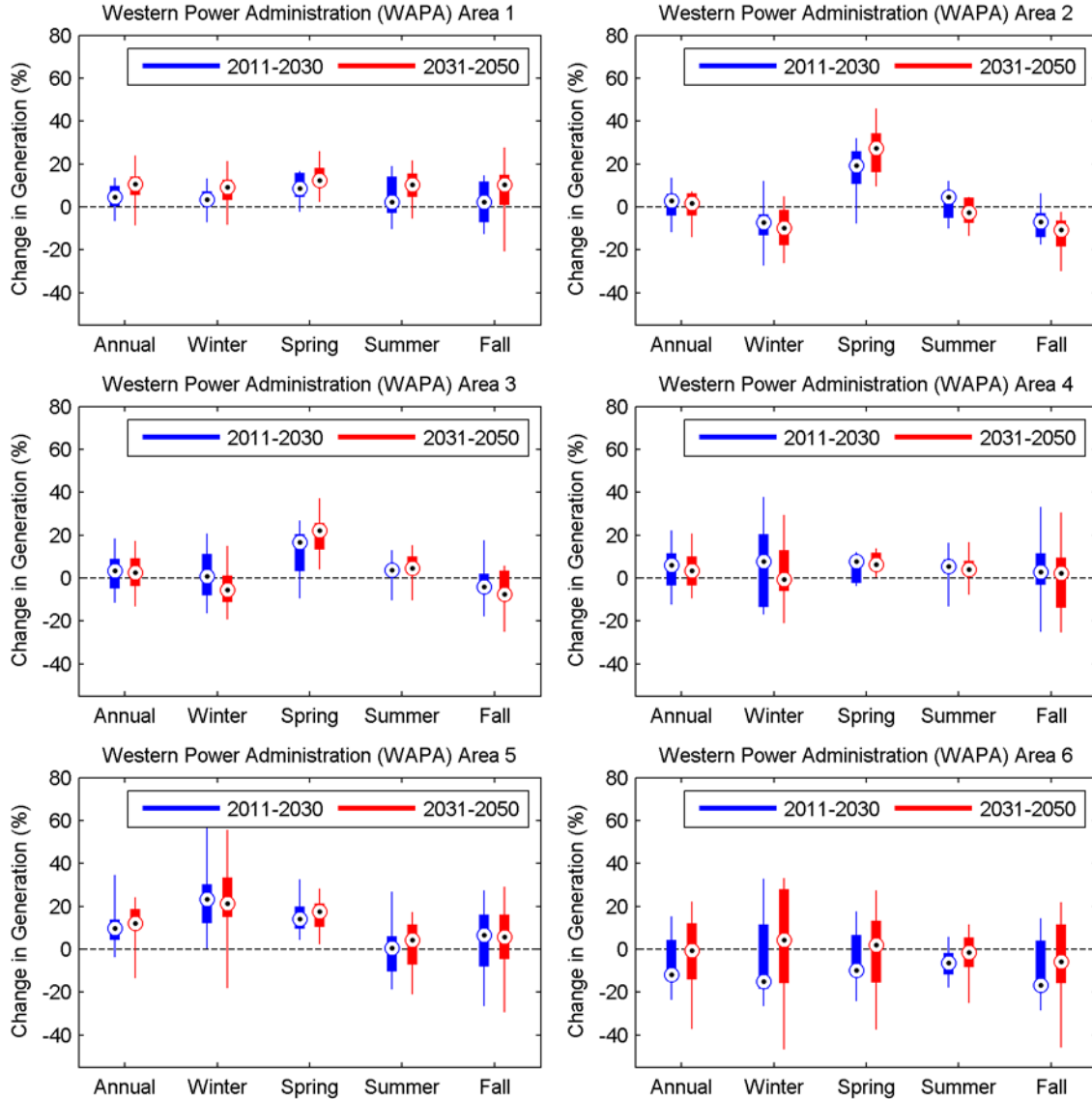


Fig. 4.12. Projected change of annual and seasonal total generation in the Western region.

Despite the obvious increasing trend in the future annual temperature (Fig. 4.2), no related trend is observed in the annual hydropower generation (Fig. 4.11). As discussed in other sections, hydropower is a favored source of electricity generation due to its operational flexibility and lower maintenance costs (i.e., the “fuel” is generally free of charge and renewable). Therefore, when conditions allow, utilities will try to maximize the usage of hydropower before switching to other fuel-dependent energy sources to optimize revenue, especially during daily peak load periods. As a result, at the annual scale, hydropower generation is mainly controlled by water availability (runoff and precipitation) rather than temperature (Kao et al. 2015). Increasing temperature has a larger influence on the hydrologic cycle (e.g., snowmelt and evapotranspiration) and could alter the seasonal characteristics of runoff.

When comparing the projected annual and seasonal change between runoff (Fig. 4.7) and generation (Fig. 4.12), the magnitude of change in the projected generation is generally less than

the projected change of runoff. The most noticeable example is WAPA-4 (lower Colorado with Hoover Dam and Lake Mead). While runoff is projected to change significantly, especially in the near-term future period, the corresponding change in hydropower generation is much less. Considering the multiyear water storage capacity in the Lake Mead, such a modeling result is reasonable. For systems with a relatively smaller water storage capacity (e.g., WAPA-6), the projected change in generation will follow the projected change of runoff more closely. Similar observations can also be made from the findings in other hydropower study areas (Sections 3, 5, and 6). Hydropower projects in the Bonneville and Western regions possess greater storage capabilities, so the magnitude of seasonal hydropower change is less than the magnitude of seasonal runoff change. Conversely, the hydropower projects in the Southwest and the Southeast have relatively smaller storage capacity, so the projected change of seasonal hydropower generation will follow the projected change of seasonal runoff more closely. For hydropower projects with even less storage capacity or that are purely operated in a run-of-river mode, their response to runoff variability will be more direct and could be more vulnerable in the projected future climate conditions.

For federal hydropower in the Western region, the most important climate change effect is likely to be the early snowmelt and change in runoff seasonality (similar to Bonneville). With the increasing winter/spring runoff and decreasing summer/fall runoff in most of the Western region, water resource managers will need to allocate the water usage more carefully while balancing the increasing probability of extreme runoff and flood events. Given the relatively larger storage in the Western region, the system is likely to be able to absorb part of the runoff variability and hence may continue to provide stable annual hydropower generation in the projected near-term and midterm future periods. However, such findings are based on the assumption that there is no significant change in the future installed capacity and operations. Issues such as aging infrastructures, competing water usage, and other environmental constraints may reduce the system's ability to mitigate runoff variability and present additional demands on an already highly constrained system.

4.3.2 Climate Change Impacts on Federal Power Marketing

Impacts on Supply

The results from Section 4.2 provide a good starting point to discuss the impacts of climate change on power marketing in the Western region. Climate models project increases in temperature for all Western areas in all seasons, with larger temperature increase during the spring and summer seasons (Fig. 4.3). Projected winter precipitation also displays increases in all Western study areas except for WAPA-5 (Fig. 4.5). Due to differences in hydrology and project configuration, the effects of those projected climatic trends on the volume and timing of generation are not uniform across the various marketing regions.

To aid the discussion of regional impacts, Table 4.3 maps the regions used in the 9505-2 study to project generation and the projects and power marketing regions used by Western in its marketing activities.

Table 4.3. Map between Western’s power marketing regions and 9505 study areas

Projects	Power marketing regions	9505 study areas
Falcon-Amistad	Colorado River Storage Project Management Center (CRSP-MC)	WAPA-5
Provo		WAPA-3
Salt Lake Integrated Project		
Parker Davis	Desert Southwest	WAPA-4
Boulder Canyon		
Central Valley	Sierra Nevada	WAPA-6
Loveland	Rocky Mountain	WAPA-2 / WAPA-3
Pick-Sloan Missouri Basin-Eastern Division	Upper Great Plains	WAPA-1

The largest Western project in terms of energy generated is the Pick-Sloan Missouri Basin-Eastern Division. It corresponds to the WAPA-1 region, for which the WRES model projects an increase in generation in all seasons for the entire 2011–2050 period. The Rocky Mountain and Colorado River Storage Project (CRSP) regions mostly correspond to WAPA-2 and WAPA-3.²⁸ For those study regions, the WRES model projects no significant changes in annual generation but a large seasonal change: increase in spring generation due to earlier snowmelt and generation decreases in all other seasons. The Desert Southwest region is located in WAPA-4. The WRES model projects large changes in runoff for that region. However, the ample storage capacity provided by Hoover Dam and Lake Mead smooths out water availability so that the resulting change in median annual generation is a moderate increase (7%). Finally, the Sierra Nevada Region corresponds to WAPA-6. For this region, the multimodel median projection indicates a significant decrease (13% relative to the baseline period) in annual generation in 2011–2030 and a recovery to levels close to the baseline in 2031–2050.

Impacts on Demand by Western Customers

The type of customers Western serves and the season in which their demand peaks are important features in discerning the impact that projected climate trends will have on their demand profile. The vast majority of customers that have long-term contracts with Western are preference customers with a high fraction of temperature-sensitive residential and commercial loads. As for seasonality, Western is a summer peaking system. EIA Form 861 data for 2007–2013 show that summer peak demand for Western was between 18% and 33% larger than the winter peak demand during those years.²⁹ Combined with the projected increasing temperature trend, those two features suggest that the difference between summer and winter peak demands by Western customers could be exacerbated in the future.

Potential increases in summer peak demand by Western’s customers do not translate into new obligations for Western because its mission is to market the available federal hydropower generation rather than to serve a specific fraction of customer demand. However, increases might

²⁸ The CRSP region also contains the two projects (Amistad and Falcon) in the WAPA-5 region.

²⁹ This is the total for the whole Western service area. Some regions in the upper Great Plains (North Dakota, South Dakota, and Montana) consume more energy during the winter than during the summer.

affect Western's expenditures, which are ultimately borne by its customers. Increases in summer peak demand could result in electricity price increases during the summer, as the more inefficient generation units would need to come online. Those higher prices would make Western's wholesale power purchases during the summer months more expensive.

A detailed statistical analysis of the demand-temperature relationship for Western's customers is out of the scope of this study, but existing literature offers some insight into the possible magnitude of temperature-induced electricity demand increases in the Western US. These detailed studies regarding the relationship between temperature and electricity demand in Western's footprint have been conducted for California. Franco and Sanstad (2008) estimate two linear relationships: total daily consumption as a function of average temperature and total daily consumption and maximum hourly demand as a function of maximum hourly temperature. These linear relationships are used to predict changes in peak demand and total consumption. Based on the estimated curves and the temperature projections from three different models, the increase in peak demand would range between 1.6% and 11.2% in 2035–2064 (relative to 2004–2005), and total annual consumption would increase between 1.6%–8.1% (relative to 1961–1990).

Aroonruengsawat and Auffhammer (2011) use billing data for 2003–2006 to econometrically estimate the temperature responsiveness of electricity consumption for residential customers in California, accounting for differences in building codes in different parts of the state. The estimated relationship between consumption and temperature also takes into account electricity price, precipitation, and household characteristics. Predicted overall electricity consumption increases between 18% and 55% by the end of the century relative to the 1980-1999 baseline. The magnitude of this predicted increase is higher than in other studies because they find that the response of electricity consumption to temperature is highly nonlinear at high temperatures. The Central Valley and areas of southeastern California are the zones with the largest predicted increases. The Central Valley is precisely the area where most of California hydropower projects marketed by Western are located.

Results obtained for California, which consumes a small fraction of Western's marketed energy, do not necessarily extrapolate to the rest of Western's region because of climate differences, differences in the levels of electric versus natural gas heating utilization, and building efficiency requirements, among other factors. Lu et al. (2010) focus on temperature effects on cooling loads at residential and commercial buildings in selected cities throughout the western US for 2045–2054 compared to a 1996–2006 baseline. They use a building simulation model that estimates changes in building energy use associated with changes in temperature for 26 building types. According to their findings, on average, the residential buildings experience more than a 10% peak load increase, while the most temperature-sensitive commercial buildings experience increases in the 5%–10% range. In Southwestern interior cities (Phoenix, Salt Lake City, and Boulder), the peak demand levels that occurred only during summer in the baseline period extend to part of the spring and fall months in the forecast period. Total energy consumption increase in summer months is greater than 10% for most building types and most cities.

These studies agree that both summer peak demand and total electricity consumption will increase. The projected increases for the second part of this century are often in the double digits, but projected ranges are broad. It should also be emphasized that these studies focus on the responsiveness of electricity demand to temperature, assuming that other structural factors (e.g.,

building codes, efficiency of air conditioning equipment, and participation in demand response programs) stay constant over the projection period.

Impacts on Western's Marketing

The combination of projected generation changes, projected demand changes, and specific characteristics of each project and marketing plan needs to be taken into account to assess potential climate-related impacts on Western's long-term contracts and power rates. For the projects in which Western sells only energy (Amistad, Falcon, Provo, and Central Valley), the uncertainty and costs associated with annual hydrologic variability is born entirely by the customers. In these projects, Western does not have to purchase replacement power or sell surplus power to buffer the annual variability in generation. The annual revenue requirement and the available energy from these projects are allocated in predetermined fractions among the customers. For a given revenue requirement, if climate change results in generation increases (as it is projected for the Amistad and Falcon projects), the rate paid per kilowatt-hour decreases. In the Central Valley Project, where generation is projected to decrease, the rate per kilowatt-hour increases (unless the annual repayment requirement is modified). The challenge for Western could arise if generation decreases to the point that the required rate per kilowatt-hour makes federal hydropower generation in this region not competitive with alternative sources of electricity. Under those circumstances, customers might not want to extend their contracts.

For the rest of the projects (Pick-Sloan Missouri Basin, Loveland, Parker-Davis, Boulder Canyon, and Salt Lake Integrated Project), Western sells capacity and firm energy. When negotiating the long-term contracts with its customers, Western determines the marketable resource (i.e., total capacity and energy to be marketed) for the next contract period and allocates it among the customers.³⁰ During the allocation process, Western also decides how the firm energy offered to the customers will vary by season.³¹ Climate-related changes in supply and demand can have impacts on each of those decisions as well as on the power rates.

The projected annual generation increase for the Pick-Sloan Missouri Basin project suggests that the marketable resource in this project could be increased in the future. Whether the marketable resource is updated or not will partly depend on the type of data used to take the decision (historical information versus forward-looking projections) and on how conservative the decision is. For instance, depending on the project, the marketable resource is set based on an average generation year or on the level of generation that can be expected for a given fraction (e.g., 90%) of the years.

The seasonality of capacity and energy allocations is another important component of the marketing decisions made by Western. For the Loveland and Salt Lake Integrated Project, the WRES model projects annual generation to undergo a seasonal shift towards more generation in the spring and less in the rest of the year.³² This projection could play a role in future Western's decisions regarding the summer versus winter firm energy allocations in these projects. The

³⁰ With a five-year notice to the customers, Western can adjust the capacity allocations based on changes in hydrology or river operations.

³¹ The summer season extends from April through September, and the winter season goes from October to March.

³² Similarly, the 2011 Bureau of Reclamation hydrology study that Western is using to formulate its post-2024 Loveland allocations proposal projects a shift in generation from winter months into spring and fall months.

decision of how much summer versus winter firm energy to offer depends on multiple factors. According to the projected increases in summer peak demand, Western's customers would likely prefer to shift more of their energy allocation from winter to summer. Western will have to balance that preference with all the constraints in their system. Minimum flow release requirements and other environmental requirements, as well as competing use demands, limit Western's flexibility to schedule generation at the hours or months in which it would be most valuable for its customers. The storage reservoir capacity in each project will also partly determine how much water can be carried from the high-streamflow spring season to the hotter summer months. For instance, total firm energy allocated to the summer season in the Boulder Canyon project, which contains the largest water reservoir in the US, is 132% higher than the total firm energy allocated to the winter season. In contrast, in the Loveland project, total summer firm energy allocation is 21% higher than the total winter firm energy allocation.³³

To fill the gap between varying hydroelectric generation and the firm (i.e., constantly available) energy marketed to its preference customers, Western purchases replacement power from the wholesale market or arranges longer-term energy purchases from specific generation resources.³⁴ If the electricity generated is more than needed to achieve the required level of firm power deliveries to the preference customers, Western sells the surplus power either to the customers or on the wholesale market. Discrepancies between available generation and contracted levels of firm energy are not only due to hydrology, but they are also due to operational restrictions or unit outages. For instance, the Salt Lake Integrated Project has heavy purchase power requirements because of environmental release restrictions below Glen Canyon Dam.

Replacement power purchases and surplus power sales are reflected in the rates charged to customers by Western. For projects whose rates include a drought adder or cost recovery charge, the customer receives a clear signal of the weight of that component in their overall rates. To reduce its replacement power purchase requirements and offer more flexibility to customers, Western's recent power sales contracts give customers the choice of having Western buy firming power for them (beyond what is available from federal hydropower generation), or they can buy it themselves. The latter option is typically chosen by large customers that have their own generation resources or can access the wholesale market.³⁵

While long-term trends in temperature and precipitation should eventually be reflected in the long-term contract conditions for each project, replacement power purchases and surplus power sales are an important tool to manage the increased frequency of drought and flood years. Reclamation, which owns most of the projects whose power is marketed by Western, is pursuing a variety of strategies for enhanced adaptability and resilience of its water infrastructure in response to the increased frequency of flood and drought events. Some examples include the publication of guidelines for the operation of Lake Powell and Lake Mead reservoirs during drought conditions, the installation of a generation optimization system in all its power plants in the region to help maximize generation from available water, and the installation of low-head

³³ The Boulder Canyon figures correspond to the Post-2017 final allocation for that project. The Loveland figures correspond to the Post-1989 Marketing Plan allocations for that project, which have been extended until 2024.

³⁴ Western has not purchased power via a contract for more than a five-year duration in the last 20 years. Some preference customers oppose Western's involvement in long-term contracts, arguing that the main risk these purchases would cover (prolonged drought) is highly uncertain. Customers would bear the costs of these purchases, which might turn out to be unnecessary.

³⁵ <https://ww2.wapa.gov/sites/western/newsroom/pubs/Documents/How%20Western%20Does%20Business.pdf>

turbines at Hoover Dam. The low-head turbines, which are being financed by Western's customers receiving power from that project, allow for efficient operation of the turbines over a wider interval of reservoir elevations.³⁶

Western's Interaction with the Wholesale Market

In its strategic roadmap for the next decade, Western identifies changes in market design in the West, compliance regulations, and increased penetration of variable renewables as key topics that will affect Western and its customers.³⁷ Western interacts with the surrounding electricity markets as a wholesale marketer, as a balancing authority, and as a transmission infrastructure developer.³⁸ As a wholesale marketer, Western focuses on the price and the number of available counterparties that will be available when conducting surplus sales or power purchases. Climate change might affect price levels and seasonal price patterns. Moreover, new market initiatives throughout the West affect the conditions under which wholesale transactions can be made with different counterparties. As a balancing authority, Western is required to comply with all NERC grid reliability requirements and address challenges associated with the integration of increased generation from variable renewables. The extent to which federal hydropower is required to balance the fluctuations from wind and solar generation depends on the generation mix in each balancing authority and the degree of coordination with surrounding balancing authorities. The discussion of Western's interaction with the wholesale market should take regional differences in generation mix and market structure in the various power marketing regions into account.

Regarding the relationship between generation marketed by Western and wholesale market price, Fig. 4.13 shows the trend and seasonal patterns over the 2005–2012 period. No single wholesale price is representative of market conditions in the entire Western service area. The correlation between total hydropower generation marketed by Western and price hubs in the region is low.³⁹

A more appropriate correlation analysis involves exploring the relationship between price hubs and overlapping Western power marketing regions. For the NP15 hub in northern California, the most relevant generation data corresponds to Western's Sierra Nevada region. The correlation between those two series from 2009 to 2012 is -0.27. For the Palo Verde Hub—located in Arizona—the overlapping power marketing region is the Desert Southwest region. The correlation between Desert Southwest generation in that region and the Palo Verde hub price was 0.086 between 2005 and 2012.⁴⁰ Thus, correlation between the timing of generation marketed by Western and representative wholesale electricity prices in the region is weak.

³⁶ Future efficiency improvements to be enabled by these capital investments are not captured in the generation projections in this report.

³⁷ <https://ww2.wapa.gov/sites/western/newsroom/pubs/Documents/SOA2015.pdf>

³⁸ In 2009, as part of the American Recovery and Reinvestment Act, Western received borrowing authority up to \$3.25 billion for investment in its transmission infrastructure.

³⁹ The correlation coefficient between Western's monthly generation and the Arizona-Palo Verde monthly average wholesale price from 2005 to 2012 is -0.099. For the 2009-2012 period and monthly NP15 (northern California) wholesale price is -0.2837.

⁴⁰ This correlation coefficient is not statistically significant. Its p-value is 0.40.

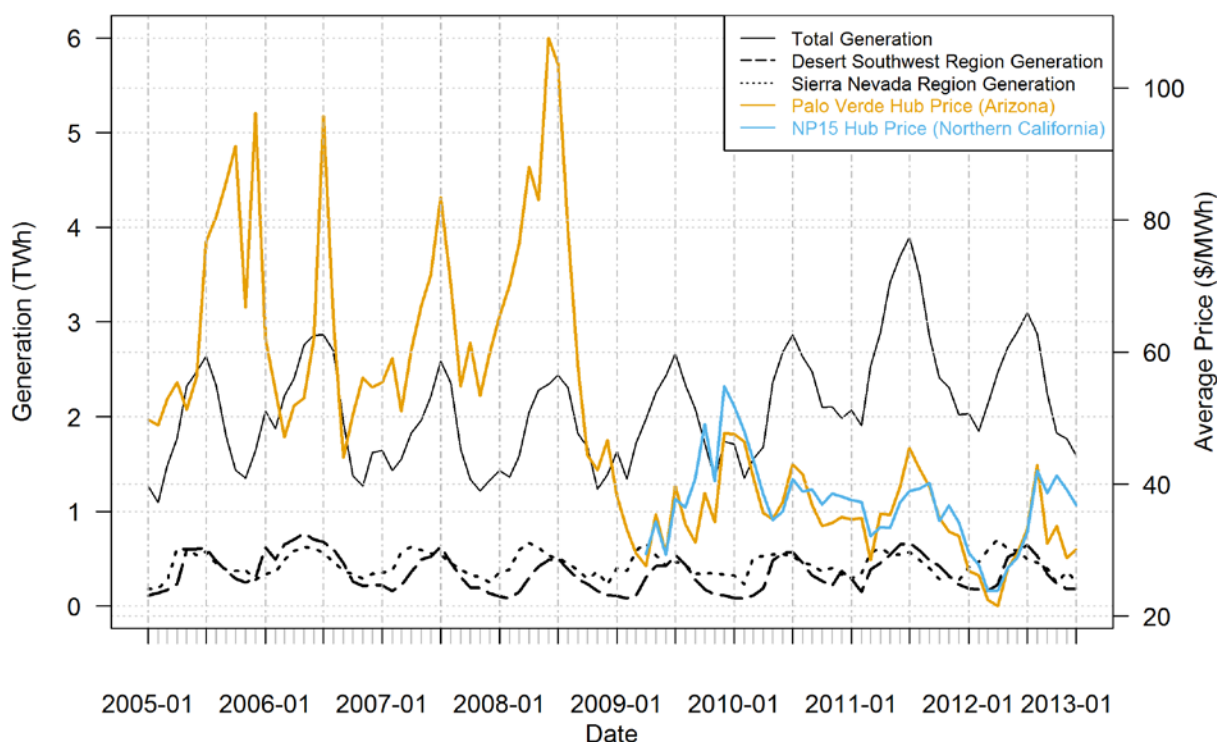


Fig. 4.13. Monthly hydropower generation in Western's power marketing regions versus monthly average wholesale prices. Sources: Price data series correspond to the average price of day-ahead transactions at the Intercontinental Exchange and were obtained from EIA.

The percentage of total generation that hydropower represents in each region influences the price that Western will pay for replacement power purchases or the price it will receive for surplus power sales. That percentage varies greatly across the 13 states based on location. For 2011–2013, the highest fractions correspond to some of the states in the upper Great Plains region (69% in Idaho, 48% in South Dakota, and 39% in Montana) and the Sierra Nevada region (15% in California). In the rest of states, hydropower represents less than 10% of the generation. Thus, wholesale prices are more likely to increase in years with below-normal precipitation in those two regions. Consequently, it is also more likely that in those two regions, the periods in which Western needs to purchase replacement power will coincide with periods in which wholesale prices are high.

Generation mix also affects Western's role as balancing authority. Western operates four balancing authority areas with substantially different generation mixes.⁴¹ The Western Upper Great Plains West (WAUW) and Western Upper Great Plains East (WAUE) correspond to the Upper Great Plains power marketing region (WAPA-1). In the WAUE and WAUW balancing authority areas, hydro and wind make up the bulk of the installed nameplate capacity: 81% and 100% respectively (EIA 2014a). The Western Colorado Missouri (WACM) balancing authority is a thermal-dominated system which geographically corresponds to WAPA 3. Only 8.6% of installed capacity in WACM is hydropower, and only 1.8% is wind (EIA 2014a). Finally, the

⁴¹ A map of all the NERC reliability regions and balancing authorities can be found at http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/BA_Bubble_Map_20140630.jpg

Western Lower Colorado (WALC) corresponds to the Desert Southwest power marketing region (WAPA-4). For WALC, 67.5% of the installed capacity is hydropower, with the remainder comprised of thermal generation (EIA 2014a). Given these different mixes, the degree to which renewables integration is a concern for Western varies across balancing authorities.

The balancing authorities in the Upper Great Plains Region (WAUW and WAUE) are hydro-dominated, and they also have the highest penetration of wind generation. With this generation mix, Western would be required to rely heavily on hydropower units to provide operational reserves. The extent to which hydropower units must play this role might decrease if Western's Upper Great Plains Region were a member of a wider balancing area with more diversity in the generation mix. During recent years, the Upper Great Plains region had experienced challenges for delivering energy to preference customers located in the Midwest Independent System Operator (MISO) or Southwest Power Pool (SPP) footprints due to transmission congestion. The protocols in place to alleviate congestion resulted in reducing electricity flow in and out of these RTO footprints and redispatching generation within the footprints. One way to avoid this problem was to become a member of the RTOs and thus be within the footprint. To address the transmission congestion issues and renewables integration challenges, Western conducted a study that evaluated the costs and benefits of its Upper Great Plains region becoming a member of MISO or SPP. The study concluded that joining SPP was the most attractive option for that region (WAPA 2013). Full membership of the Upper Great Plains power marketing region in the SPP will become effective in October 2015.

Other Western power marketing regions have considered joining the CAISO/PacifiCorp EIM that went live on November 2014. An EIM focuses on resolving short-term imbalances due to discrepancies between forecasted and actual generation. A 2014 study concluded that the benefits for the Western balancing authorities joining the CAISO/PacifiCorp EIM would not fully offset the costs.⁴² One of the reasons that Western cannot take full advantage of the benefits of market participation is because the many competing priorities in federal hydropower operation result in a limited ability to dispatch power according to the market signals. Operational constraints due to competing uses and mitigation of environmental impacts partly explain the weak correlation between generation and market prices for the Western region presented in Table 2.4 and Figure 4.13. A possible concern for Western stems from the fact that most of the surrounding balancing authorities are joining the CAISO/PacifiCorp EIM. As more market participants join the EIM, the number of nonmember trading partners with whom Western can transact decreases. Trading with partners that are members of the EIM is possible, but it might entail congestion charges like those experienced by the Upper Great Plains region.

Changes in Western's electricity market structure have been partly caused by the large growth in wind and solar installed capacity over the last decade. As a power marketer and transmission operator, Western will be required to continue navigating the changes to generation mix and market structure over the coming decades. On one hand, Western actively encourages its customers to install additional renewable energy projects by offering technical and marketing assistance. On the other hand, renewable energy developers argue that the current situation in which Western does not enter into purchase power agreements of more than five-years in duration and is not part of a RTO make independent renewable energy development in Western's

⁴² <http://ww2.wapa.gov/sites/western/newsroom/NewsFeatures/NF2014/Pages/UnderstandingMarkets.aspx>

control areas unattractive.⁴³ Some of Western's preference customers fear that, as the penetration of wind and solar increases, federal hydropower will be dispatched as dictated by the availability of those renewables rather than when it would be most valuable to the federal power customers.

⁴³ http://ww2.wapa.gov/sites/western/powerm/pmirp/Documents/Iberdrola_001.pdf

5 THE SOUTHWESTERN REGION

Utilizing the methodology described in Section 2, the assessment results for federal hydropower plants marketed through Southwestern Power Administration (SWPA or Southwestern) are summarized in this section. The study area definition, background hydropower, and marketing characteristics are described in the first subsection. The hydroclimate projections, along with a literature review of other hydroclimate studies in this region, are presented in the second subsection. The potential impacts on federal hydropower generation and risks to federal hydropower marketing are discussed in the third subsection.

5.1 Regional Characteristics

5.1.1 Study Areas

The Southwestern region includes rivers that run through the Ozark Plateau, the southern Great Plains, and the Texas coastal plains. There are 24 hydropower plants 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 TWh/year (see Appendix B for the complete list of federal hydropower plants) (NHAAP 2014). Considering power system and watershed boundaries, the Southwestern region is subdivided into four study areas (Fig. 5.1):

- Southwestern Area 1 (SWPA-1) – Upper White, Osage and Salt: Ozark Plateau rivers in Missouri and northern Arkansas (Osage, upper White, and Salt River Basins)
- Southwestern Area 2 (SWPA-2) – Arkansas: 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) – Ouachita, Red and Brazos: 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) – Neches: the Neches River Basin in southeastern Texas

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 (described in the previous two sections).

The first study 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 mi². Elevations range from 300 to 2,400 ft, with a median of 981 ft.

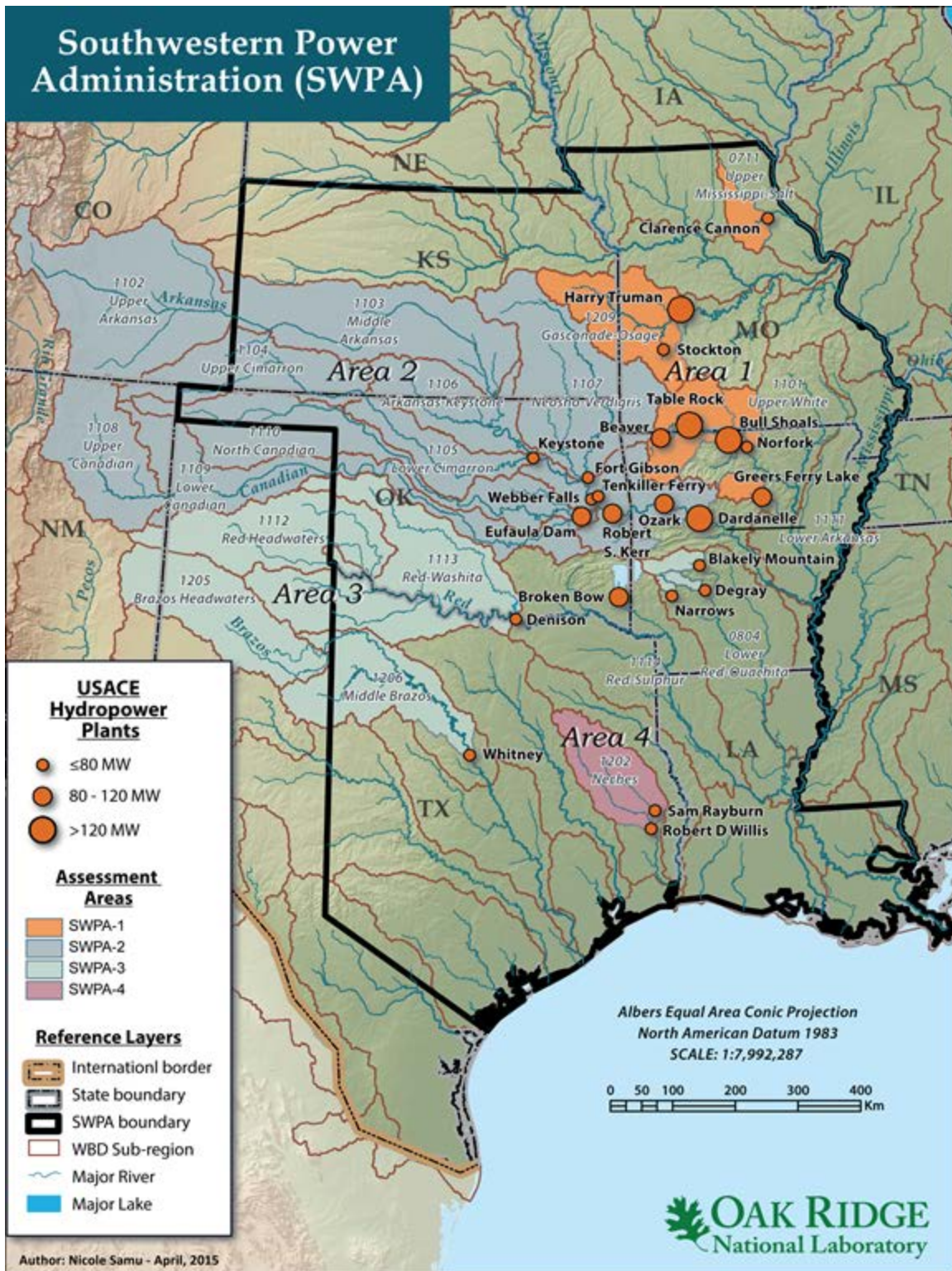


Fig. 5.1. Map of the federal hydropower plants and study areas SWPA 1-4 in the Southwestern region.

As a whole, Southwestern is significantly lower in elevation than Bonneville or Western, and the topography strongly influences surface water hydrology. Land cover in SWPA-1 is a mix of

cropland (37%), cropland-natural vegetation mosaic (34%), deciduous broadleaf forest (12%), and grassland (9%).

The second study 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 mi². Elevations vary greatly, from over 14,000 ft in the Colorado Rocky Mountains to around 300 ft in the vicinity of the hydropower projects clustered in the eastern end of the river basin. The median elevation is 2,392 ft. 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 study area, SWPA-3, covers three different river basins: 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 mi². Elevations range from almost 5,000 down to 300 ft, with a median of 1,720 ft. Grasslands cover 82% of the watershed.

The fourth study 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 mi², and elevations range between 774 and 72 ft, with a median of 341 ft. 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 in the Southwestern Region

All federal hydropower projects in the Southwestern region are owned and operated by USACE (Table 5.1). There are 24 USACE hydropower plants in the region, ranging in size from Bull Shoals (340 MW) to the Robert D. Willis project (7.4 MW). Total nameplate capacity is 2,197 MW, but total overload capacity is substantially more at 2,478 MW (Sale et al. 2012). This is an important distinction, because hydropower operations in the region are often in a peaking mode that can be operated within the overload range. Approximately half of the hydropower capacity in this region is in SWPA-1. The average age of these USACE projects is 51 years, and they are suffering the same challenges of aging infrastructure as federal projects elsewhere. A complete list of the projects in this region is provided in Appendix B.

The water resources management challenges in the Southwestern region are similar to those in the Bonneville and Western regions. Although the rivers in the Southwestern region do not have migratory fisheries management constraints similar to those in the Columbia River or California, the hydropower projects are impacted by endangered species protection issues for animals such as the interior least tern, as well as issues pertaining to recreational fisheries management. Additionally, growing demands for municipal and industrial water supply are some of the most crucial water resource issues in the Southwestern region. Competing interests with water-based recreation, water quality, and other environmental issues are also concerns in the Southwestern region. Further details on multipurpose water management issues in the Southwestern region can be found in Sale et al. (2012).

Table 5.1. Summary of federal hydropower plants in the Southwestern region

Area	Area name	Number of plants			Total installed capacity ^a (MW)	Average annual generation ^b (GWh/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	Ouachita, Red, and Brazos	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 1970 to 2012.

5.1.3 Power Marketing by Southwestern

Southwestern is a PMA established in 1943 to market the power from the projects in the Mississippi River tributaries that were authorized by the Flood Control Act of 1927. Southwestern markets the power under the authority of Section 5 of the Flood Control Act of 1944. Since a devastating flood prompted construction of those projects, their primary mission was flood control. However, hydropower production was also an authorized purpose. Additional projects were authorized subsequently in the region until the fleet of 24 USACE multipurpose water resource projects was completed. These projects' power and related services are marketed by Southwestern today. In addition, Southwestern also operates and maintains 1,380 miles of high-voltage transmission lines. These transmission assets make up one of the 16 balancing authorities within the SPP footprint.

Southwestern markets federal power to more than 100 preference customers—cooperatives, municipalities, and government agencies—located across six states. The PMA established its current marketing plan through the federal rulemaking process as provided in the Final Power Allocations published in the Federal Register on March 24, 1980 (45CFR 19032). Southwestern conducts annual power repayment studies and produces power rate schedules for three separate systems: the Integrated System, the Sam Rayburn Dam, and the Robert D. Willis Dam. Power from the Sam Rayburn and Robert D. Willis projects (corresponding to SWPA-Area 4 in this report) is sold separately because they are “hydraulically and electrically” isolated from the rest of the system. Projects in regions SWPA-1 through SWPA-3 constitute the Integrated System.

Unlike the river systems in the Bonneville and Western regions, whose runoff mostly comes from snowpack melt, water availability for hydropower in the Southwestern region depends entirely on annual rainfall. All of the hydropower projects in this region have limited storage, and about a third of the projects are run-of-river facilities with virtually no storage capacity; as a system the projects can hold months' rather than years' worth of contracted energy allocations. Due to the uncertainty in water availability associated with this hydrologic profile, Southwestern changed its marketing strategy in 1980 from firm power to peaking power allocations, with 1,200 hours of energy per kilowatt of contracted capacity. If water availability in any given year can support more than the contracted 1,200 hours of energy, Southwestern offers the supplemental.

energy to its customers (or to other interested parties if the customers do not purchase it).⁴⁴ On the other hand, during days in which water availability or system capacity is insufficient to fulfill the contracted amounts, Southwestern acquires replacement power to make up the difference.

The rates for the Integrated System include a capacity charge (in dollars per kilowatt per month) and an energy charge (in mills per kilowatt-hour), as shown in Table 5.2. Customers receiving power from the Sam Rayburn and Robert D. Willis projects pay a flat monthly rate. The Robert D. Willis project is unique in that the power rates do not include recovery costs to design and build the hydropower plant. USACE built the Town Bluff Dam in 1951, but even though it was one of the authorized purposes, addition of hydropower production was not deemed an economically justifiable function for the project until the early 1980s. At that point, the Sam Rayburn Municipal Power Agency offered to finance the design and construction of the power plant. In exchange, this agency receives all the capacity and energy from the project for a period of fifty years.

Table 5.2. Southwestern rate schedule summary

	Capacity charge (\$/kW-month)	Peaking energy or supplemental. peaking energy rate (mills/kWh)
Integrated system	4.50 ⁴⁵	9.4 (base) 5.9 (purchased power adder, does not apply to supplemental. peaking energy sales)
Hydro Power and Energy sold to Sam Rayburn Dam Electric Cooperative	Flat rate: \$352,510/month	
Hydro Power and Energy sold to Sam Rayburn Municipal Power Agency	Flat rate: \$83,405/month (Jan-Sep, 2015) Flat rate: \$98,458/month (Oct 2015- Sep 2018)	

Note: 1 mill = \$0.001

For the Integrated System, the most recent set of rates became effective in October 2013, incorporating a 5.4% revenue requirement increase relative to the previous schedule. The monthly rate for energy from the Sam Rayburn project was increased by 7.1% in 2013. Rates for the Robert D. Willis project were last revised in December 2014, resulting in a 10.4% increase that is being applied in two steps in January and October of 2015. Compliance with expanded regulatory initiatives (e.g., new NERC standards) and maintenance and replacement of aging equipment infrastructure have been cited among the reasons for these increases (Turner 2013).

Southwestern can adjust the purchased power adder component, which is designed to recover the costs of replacement power purchases, up to two times annually by an amount up to a total of plus or minus 5.9 mills/kWh. The adjustment depends on the difference between Southwestern's actual and estimated expenditures in replacement power. The current adder adjustment rate is set at 2.1 mills/kWh. Combining the capacity charge, energy charge, purchased power adder, and adder adjustment rate into a total cost per unit of energy, the current cost of electricity for customers of the Integrated System is 62.4 mills/kWh if they only receive the 1,200 hours of peaking energy; receipt of supplemental energy will reduce the cost per kWh.

⁴⁴ If neither the preference customers nor third parties agree to purchase the supplemental energy, water spills or turbine-generator unit swings or stops may take place (Wech, 2014).

⁴⁵ It includes two ancillary services: scheduling and reactive supply/voltage control.

In order to comply with its requirements as a member of SPP's reserve sharing group, Southwestern uses some of the energy in its storage reservoirs for regulation (load following) and operating reserves purposes. The resulting lost generation is then offset by replacement power purchases if the demand is higher than the total available system capacity. The cost of those purchases is passed through as a regulation purchased adder to customers contracting this ancillary service from Southwestern. The current base rate for the regulation and frequency response service is \$0.12 per kilowatt-month. The adder is being phased in so that Southwestern recovers from customers an increasing fraction (25% in 2014 to 100% in 2017) of the replacement value of stored energy used for regulation and operating reserves.

5.2 Future Climate in the Southwestern Region

The four Southwestern study areas are located in the south central US (Fig. 5.1). Southwestern 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, which was 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).

This section presents the projections of future hydroclimate conditions in the Southwestern region. Projections based on multimodel ensemble runs are summarized in terms of mean annual and seasonal changes (i.e., spring, summer, fall, and winter) in temperature, precipitation, runoff and evapotranspiration for near-term future (2011–2030) and midterm future periods (2031–2050) as compared to the baseline period (1966–2005).

5.2.1 Regional Climate Projections

The projected annual temperature for the baseline (1966–2005) and future periods (2011–2030 near term, 2031–2050 midterm) are illustrated in Fig. 5.2, with gray lines representing projections made by different climate models, showing the annual mean temperature from ten downscaled climate models for both 1966–2005 baseline and 2011–2050 future periods, the green lines representing the multimodel median, and the black lines showing the historical 1981–2012 temperature observation from Daymet for comparison. The corresponding multimodel probability distributions in the baseline and future periods are compared in the right panel. A two-sample Kolmogorov-Smirnov test at the 5% significance level is used to determine if the difference between baseline and future periods is statistically significant. The main use of this type of interannual plot is to visualize the range of variability and trend made by each model and to evaluate if the projected trend and variability is consistent with historic observation. Since climate models are not meant to reconstruct the exact timing of the historic interannual and decadal variability, the model runs are not expected to fully follow the historic interannual values. The same condition applies when interpreting similar interannual plots of precipitation, runoff, and generation.

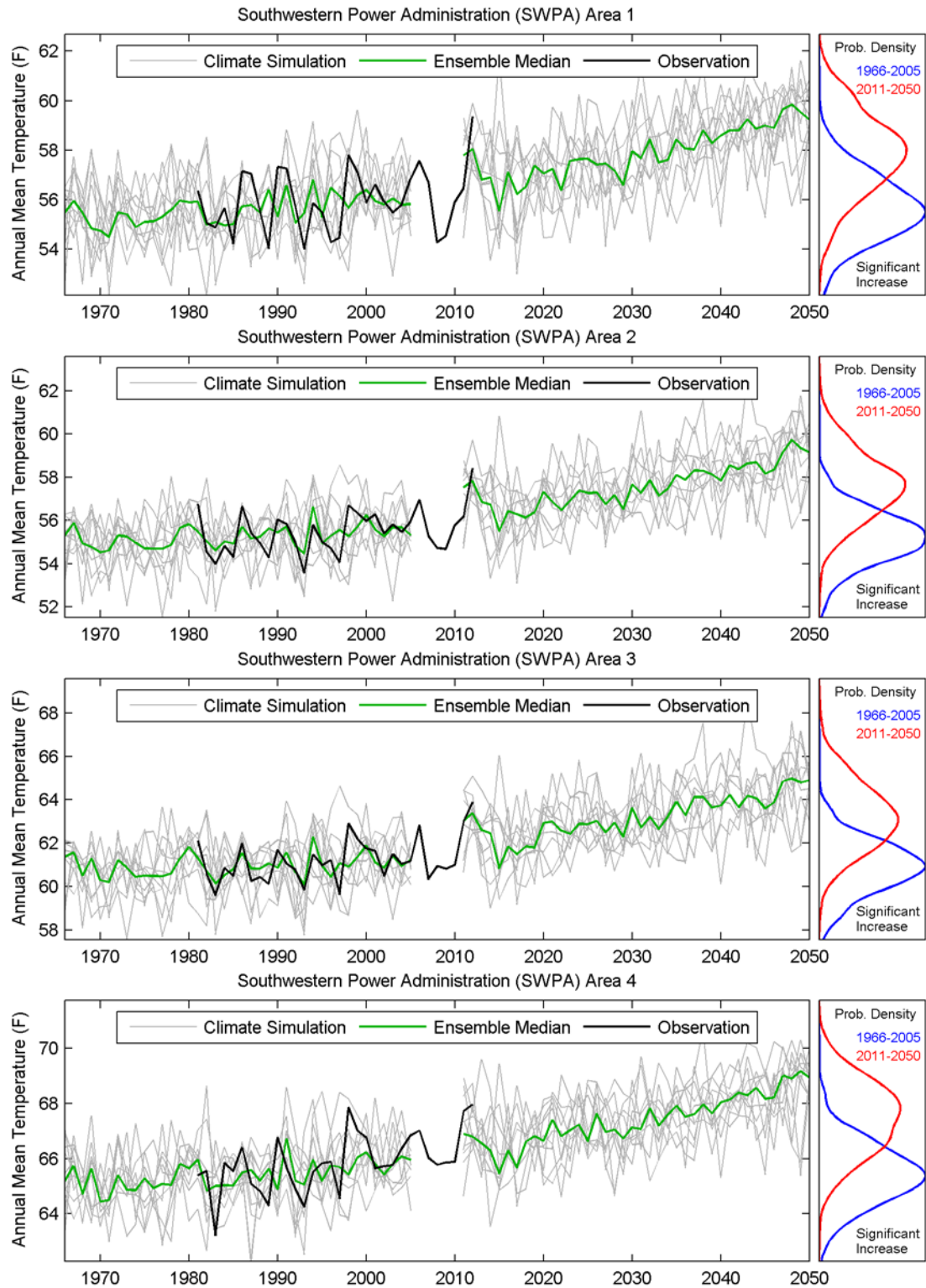


Fig. 5.2. Projected annual mean temperature in the Southwestern region.

In all four assessment areas (SWPA-1 to SWPA-4), the increasing trend in the ensemble mean annual temperature is similar to the observed temperatures, although with a large intermodel variability (Fig. 5.2). This large variability is projected, and it provides a good illustration of why a multimodel ensemble approach must be used to understand the overall picture. In the two future time periods (2011–2030 near term and 2031–2050 midterm), annual mean temperature across all areas in the Southwestern region is also projected to continue to increase. As shown in Fig. 5.2, the probability distributions of multimodel mean annual temperature for the future (2011–2050) time period also show a statistically significant warm shift in all SWPA areas.

The annual and seasonal changes of temperature are further summarized in Fig. 5.3. Change is defined as the degree difference (F) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of box indicating the 25th and 75th percentiles, and the whiskers extending to the lowest/highest models. A rapid increase is projected to occur after 2030. Mean annual temperature for Southwestern is projected to increase by approximately 2.0 °F for the near term and 3.0 °F for the midterm, compared with the baseline period (Fig. 5.3 and Appendix D). The midterm period change is the cumulative change, representing an additional warming of about 1.0 °F after the near term.

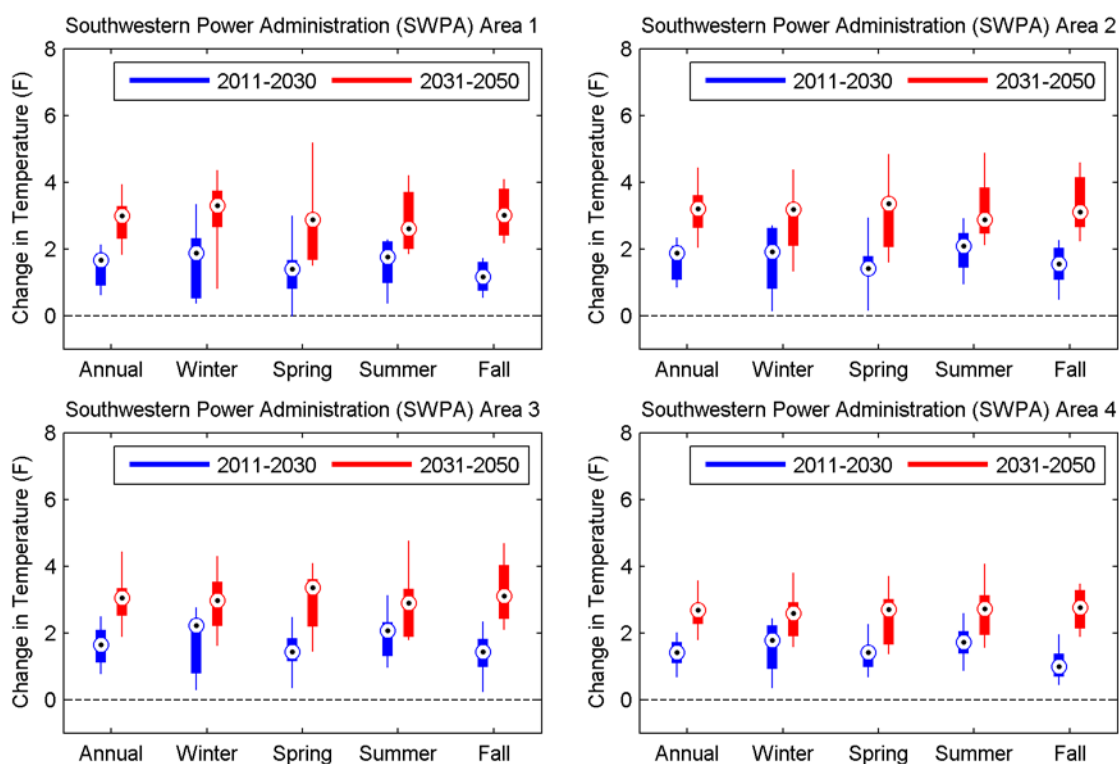


Fig. 5.3. Projected change of annual and seasonal mean temperature in the Southwestern region.

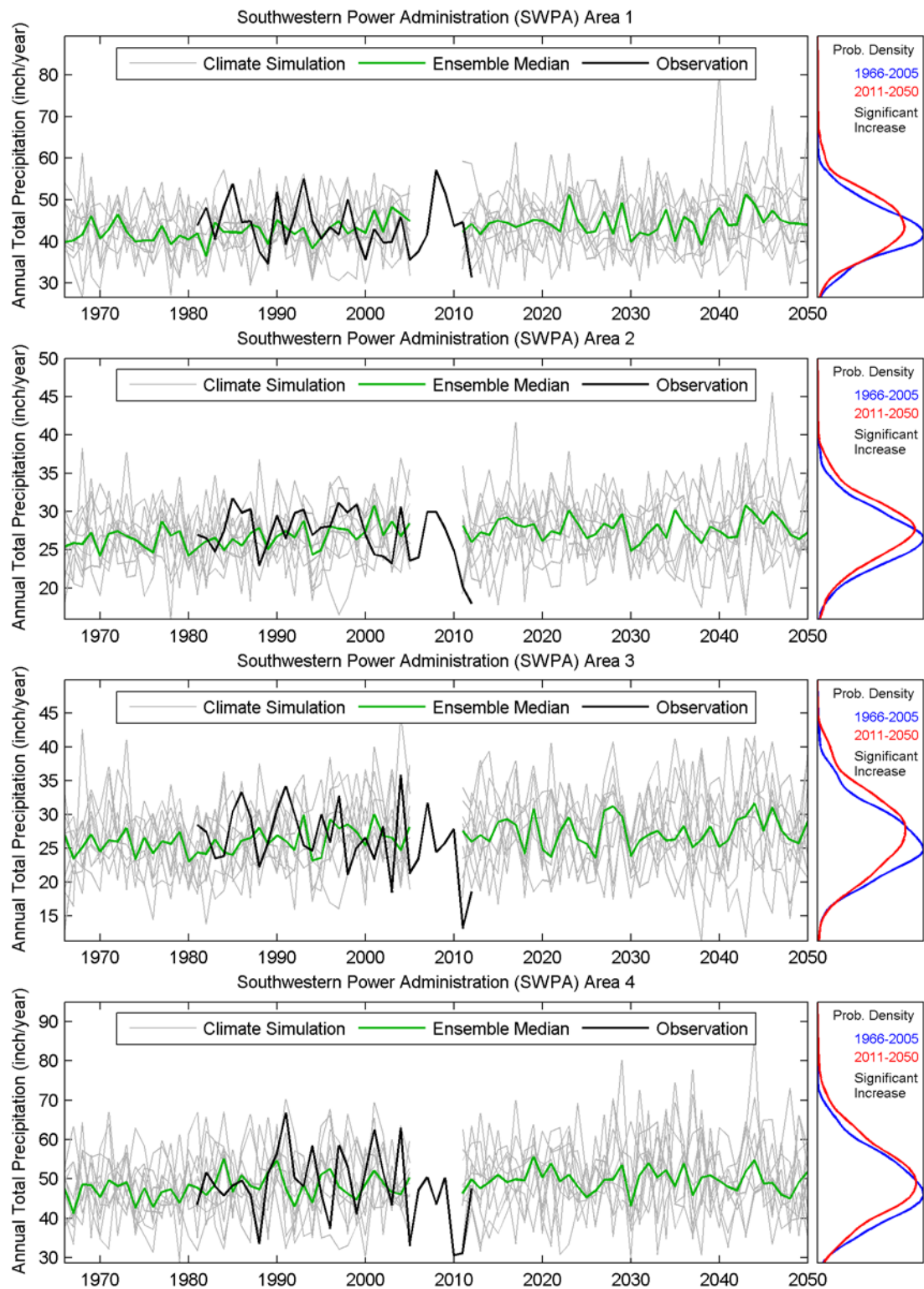


Fig. 5.4. Projected annual total precipitation in the Southwestern region.

Similar to Fig. 5.2, the projected annual precipitation for baseline (1966–2005) and future periods (2011–2030 in near term and 2031–2050 in midterm) are illustrated in Fig. 5.4. The observed and projected mean annual precipitations do not show consistent annual increase or decrease since 1966, but the probability distributions of mean annual total precipitation in the future time period does show a statistically significant increasing shift by the end of 2050 in all SWPA areas.

The annual and seasonal changes of precipitation are further summarized in Fig. 5.5, with change defined as the percentage difference (%) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. While the increases in precipitation are more pronounced in the spring and summer in all assessment areas, the winter changes show a decreasing trend, especially over SWPA-2, -3, and -4. For SWPA-1, precipitation is projected to increase. For the fall season, the change is generally smaller, with ensemble members producing both small positive and small negative changes in mean fall precipitation.

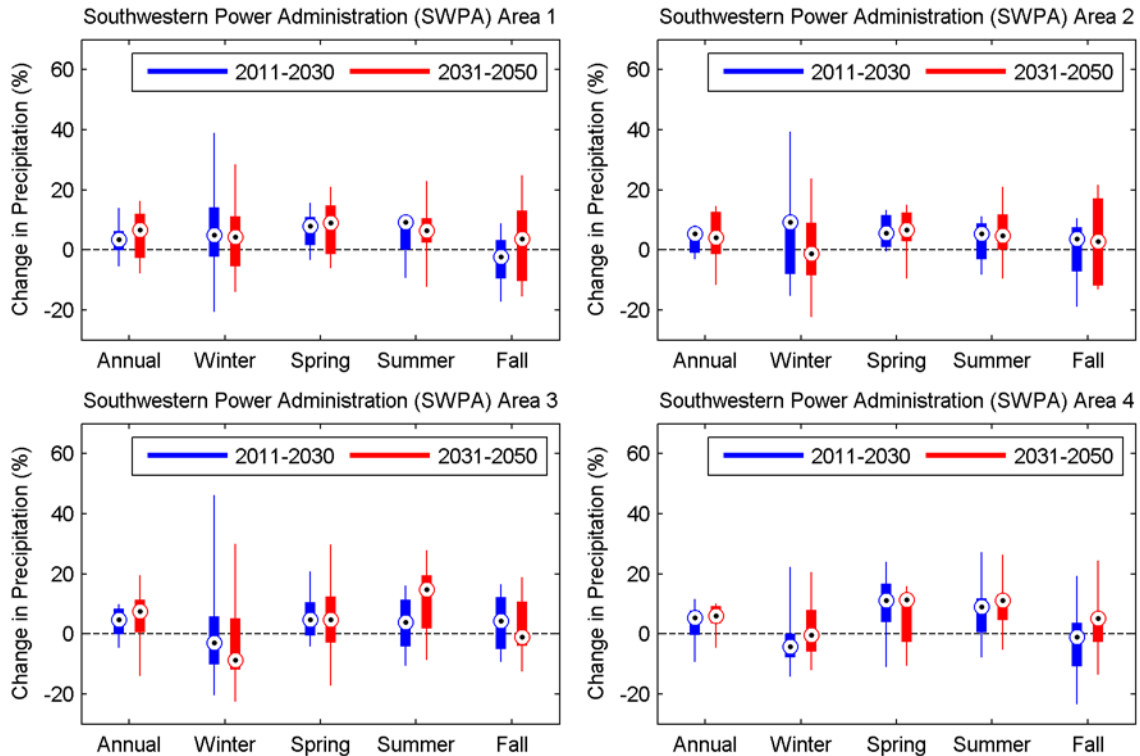


Fig. 5.5. Projected change of annual and seasonal total precipitation in the Southwestern region.

5.2.2 Regional Hydrological Projections

The hydrologic response to projected climate changes is illustrated in Fig. 5.6 and Fig. 5.7. The gray lines in Fig. 5.6 show the projected mean annual total runoff for the 10 downscaled projections averaged spatially over each Southwestern assessment area for both baseline (1966–2005) and future (2011–2030 and 2031–2050) periods. The green line indicates the multimodel median, and the black line shows the historical observation from WaterWatch from 1981 through

2012. The corresponding multimodel probability distributions in the baseline and future periods are compared in the right panel. A two-sample Kolmogorov-Smirnov test at the 5% significance level is used to determine if the difference between baseline and future periods is statistically significant. Consistent with significant increasing shifts in probability distribution of projected precipitation, Fig. 5.6 shows significant increasing shifts in distribution of runoff projections across all SWPA areas.

Similarly, on a seasonal basis, the results also show a fairly consistent increase in mean annual, spring, and summer runoff in all Southwestern assessment areas for both future time periods relative to the baseline reference (1966–2005) (Fig. 5.7). The change is defined as the percentage difference (%) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of box indicating the 25th and 75th percentiles, and the whiskers extending to the lowest/highest models. In terms of the multimodel median, the winter runoff does not show consistent increasing or decreasing trends over all areas except in SWPA-4, where winter runoff is projected to increase in the midterm future period. It should also be noted that for SWPA-1 and SWPA-2, the spread of model projections is especially large in the midterm future period, which indicates high model uncertainty and also the larger hydrologic model sensitivity (to change of precipitation) in these regions (discussed in Section 2.4.4). Nonetheless, the uniformly increasing projections of spring and summer runoff over the midterm period for all assessment areas in the Southwestern region are a strong and important trend.

The projected increases in the spring and summer runoff are also consistent with increases in spring and summer precipitation, and they may contribute to increasing spring evapotranspiration, as shown in Fig. 5.8. However, summer evapotranspiration shows a decrease to no change in all areas except in SWPA-3, where evapotranspiration is projected to increase in all seasons.

An additional extreme runoff analysis is shown in Fig. 5.9. Fig. 5.9 presents future changes in the ensemble median high runoff (i.e., 95th percentile of daily runoff) and median low runoff (i.e., 5th percentile of running 7-day average runoff) for both future projection periods in the Southwestern region. Increases in high runoff are projected in both future time periods (Fig. 5.9a and b), suggesting the potential for more extreme runoff events in all assessment areas (except for the western parts of SWPA-2 and SWPA-3). On the other hand, increases in low runoff are projected in most areas of Southwestern, with western areas in SWPA-2 and SWPA-3 showing a decreasing change in low runoff (Fig. 5.9c and d). Overall, these results suggest the possibility of more frequent flood and drought events, which could present challenges for long-term water management strategies.

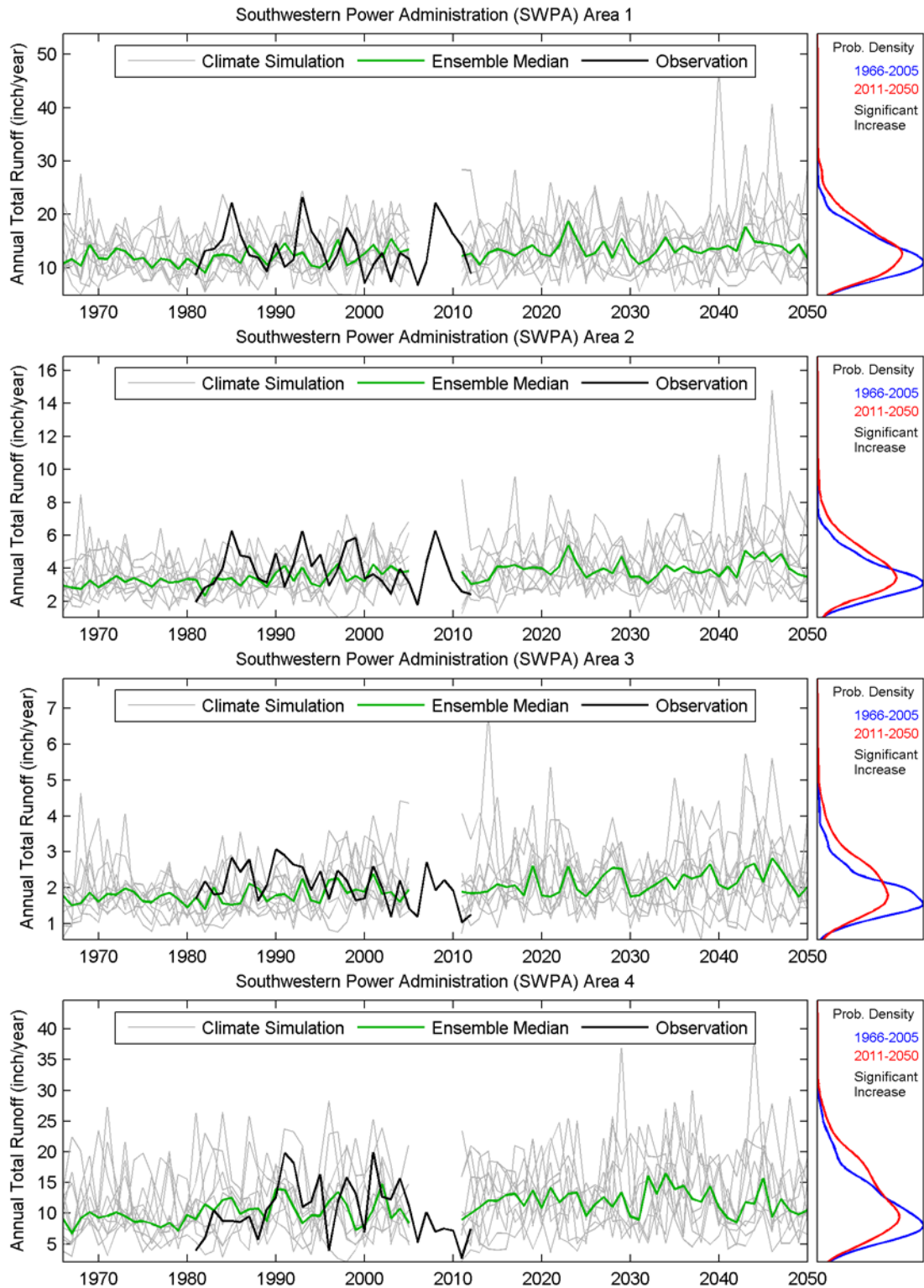


Fig. 5.6. Projected annual total runoff in the Southwestern region.

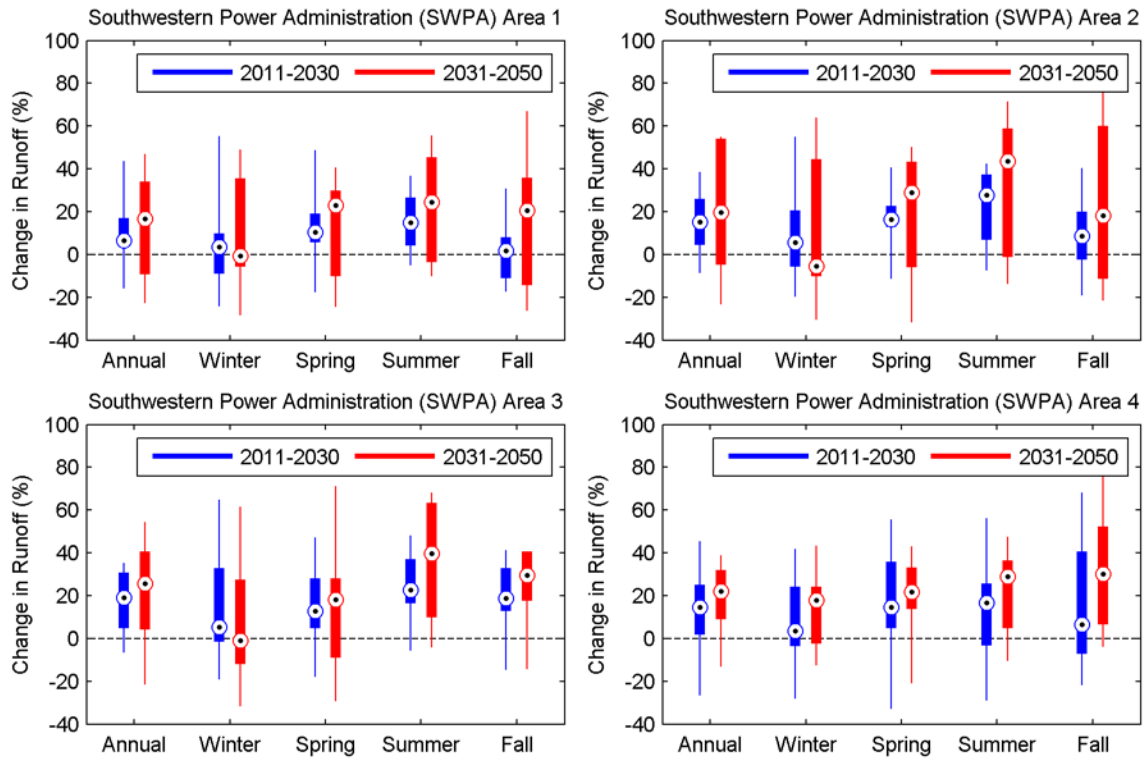


Fig. 5.7. Projected change of annual and seasonal total runoff in the Southwestern region.

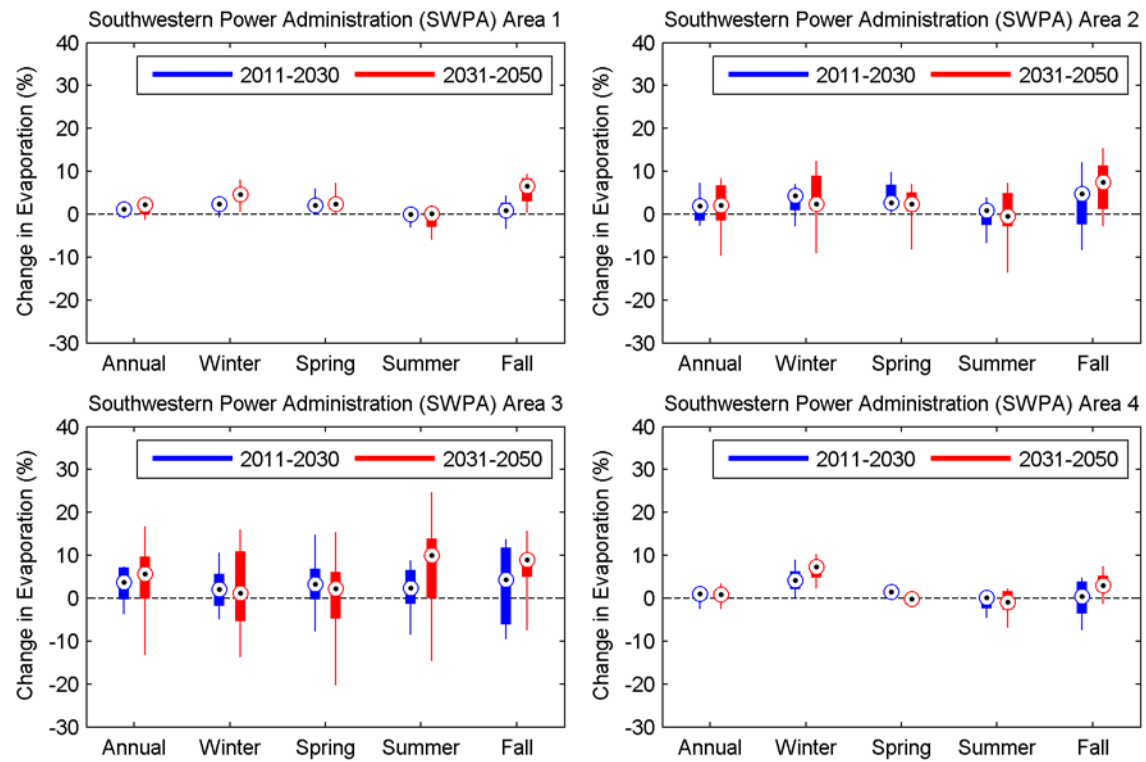


Fig. 5.8. Projected change of annual and seasonal total evapotranspiration in the Southwestern region.

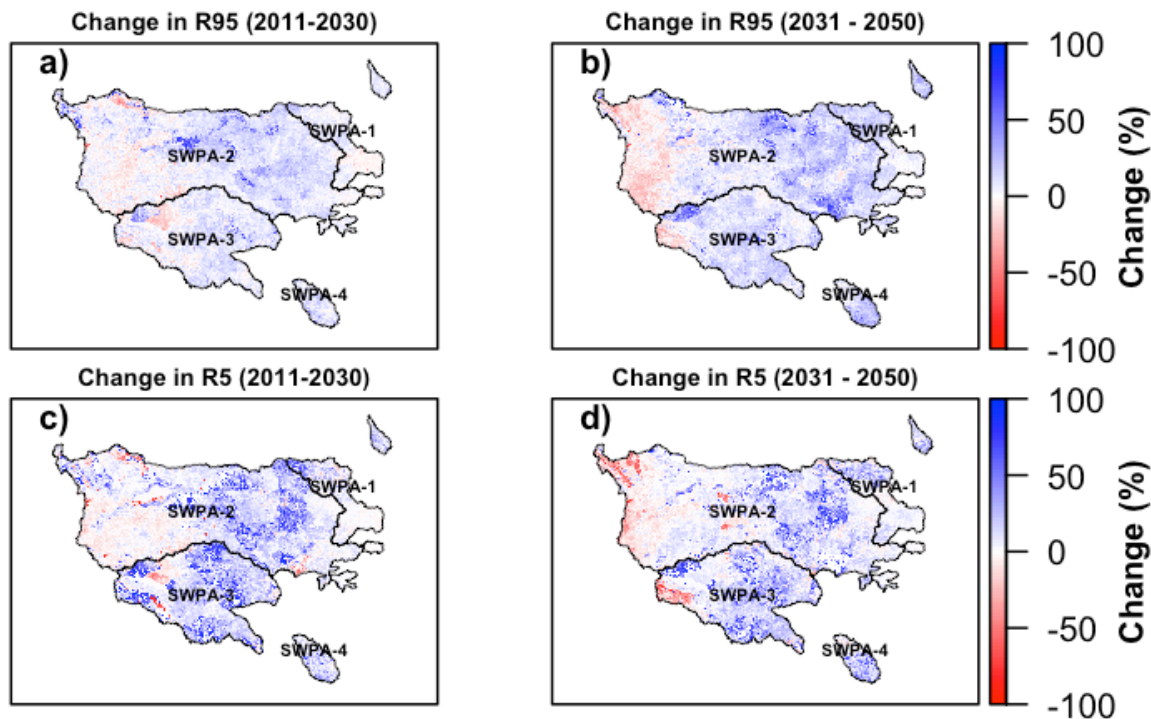


Fig. 5.9. Spatial distribution of multimodel ensemble median percentage change in (a) high runoff in 2011–2030, (b) high runoff in 2031–2050, (c) low runoff in 2011–2030, and (d) low runoff in 2031–2050 time periods in the Southwestern region.

5.2.3 Comparison with Other Climate Studies in the Region

The projections of temperature, precipitation, and runoff in this assessment for Southwestern during 2011–2050 cannot be directly compared with projections from other available studies because of several factors, such as differences in spatial domain, differences in 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.

Recent studies found a general consensus about a temperature increase in the southwestern US (Liu et al. 2012, Scherer and Diffenbaugh 2014, Kunkel et al. 2010, Ojima et al. 2013, Zhang et al. 2010). Liu et al. (2012) used the CMIP3 projections from 16 GCM models, showing a projected increase of +2 °C to +5 °C (+3.6 °F to +9 °F) annually, and the largest warming is projected for the summer and fall seasons in the Southwestern region. Zhang et al. (2010) also projected an increase of maximum temperatures between +1.0 °C and +2.0 °C (+1.8 °F to +3.6 °F) in the southwest regions (i.e., Texas and Oklahoma) at the end of midcentury for the A1B emissions scenario. While this assessment’s midterm period is not directly comparable with these results from past studies, temperature changes are generally consistent with this assessment (i.e., about +2.0 °F and +3.0 °F), as shown in Fig. 5.3. However, this assessment’s results show the largest warming in the winter and fall seasons, which is in contrast to other studies’ projections showing more warming in the summer season (Kunkel et al. 2013b, Zhang et al. 2010).

Kunkel et al. (2013b) used the WCRP CMIP3 multimodel dataset (Meehl et al. 2007) that was downscaled using statistical downscaling techniques from Wood et al. (2002) to make projections for six large regions in the contiguous US as described in the third Climate Change Assessment report. In addition to 15 CMIP3 models' projections, this study also used 11 GCM-RCM based projections as part of NARCCAP. They provided projections for each GCM-RCM combination simulation from 1971–2000, 1979–2004 and 2041–2070 for the high (A2) emissions scenario at a resolution of approximately 50 km. The southern portion of their Great Plains region largely encompasses the four Southwestern assessment areas. For the southern portion of the Great Plains, most CMIP3 model projections show decreases in precipitation for the high emission scenario at the end of 21st century. Similarly, the multimodel mean annual precipitation change from the 11 NARCCAP RCM simulations also showed a decrease in precipitation of about 6% in Texas, but positive precipitation changes are projected in the winter and fall seasons, with a decrease in summer precipitation (i.e., about 20%) over Southwestern (Kunkel et al. 2013c). In contrast, this assessment's projection shows consistent increases in precipitation during summer and decreases in the winter over Southwestern (see Fig. 5.4).

There has been very little work pertaining to projecting changes in runoff over the Southwestern region. A recent study by Seager et al. (2013) analyzed model outputs from 16 CMIP5 models under the RCP8.5 scenario to analyze precipitation minus evaporation (P - E) as a proxy for runoff in California and Nevada, Colorado and Texas regions for the 2021–2040 period. For Texas (SWPA-3 and SWPA-4 assessment areas encompass some portions of Texas), this study found a decrease in precipitation during most seasons and a year-round drop in runoff and soil moisture due to a decrease in spring and summer evaporation. In addition, the work of Milly et al. (2005), which is 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 ranging from -5 to -10% over most of Southwestern. These findings are in contrast to the projected increases in summer runoff for SWPA-3 and SWPA-4 in this assessment, as shown in Fig. 5.7. However, it should be noted that these earlier studies are based on GCM outputs that may reasonably simulate large-scale changes in precipitation and/or runoff events, but they fail to represent small-scale processes that influence warm season precipitation extremes. Conversely, dynamical downscaled climate forcings, as used in this assessment, can simulate these aspects of central US summer rainfall relatively more accurately (Harding et al. 2012).

Another study by Gangopadhyay and Pruitt (2011) analyzed model outputs from CMIP3 for 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 bias-correction spatial disaggregation (BCSD) technique of Wood et al. (2002) to generate downscaled translations of 112 CMIP3 projections which were later updated using model outputs from CMIP5 (Brekke et al. 2013). Although Gangopadhyay and Pruitt (2011) did 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 US. These include several stations in the Arkansas, Red, and Brazos basins. Reclamation's 2020s projected changes (with respect to the 1990s), while having magnitudes of less than 10%, are uniformly negative, whereas this assessment's projections consistently show a positive change in runoff (i.e., on the order of +10% to +20% in mean

annual runoff). The projected increase in summer might also be associated with the increase in precipitation simulated by most models used in this assessment when compared with the Brekke et al. (2013) projections (see Appendix C and Fig. C3). The detailed comparison of this assessment's projections and the Brekke et al. (2013) CMIP5 projections is discussed in Appendix C.

5.3 Climate Effects on Federal Hydropower in the Southwestern Region

This subsection discusses how the projected hydroclimate change may affect Southwestern's federal hydropower generation. The projected change of annual and seasonal generation is presented in Section 5.3.1. The potential risk to hydropower marketing is discussed in Section 5.3.2.

5.3.1 Projections of Hydropower Generation

Using the WRES model described in Section 2.5, the projections of Southwestern's monthly generation and watershed storage are calculated for each of the ten downscaled climate models. Projections based on multimodel ensembles are summarized in terms of the mean annual and seasonal changes (i.e., spring, summer, fall, and winter) for the near-term future (2011–2030) and midterm future (2031–2050) periods as compared to the baseline period (1966–2005).

The interannual variability of annual hydropower generation for the baseline and future periods is shown in Fig. 5.10, with gray lines showing the annual total generation from ten downscaled climate models for both 1966–2005 baseline and 2011–2050 future periods, the green line representing the multimodel median, and the 1981–2012 historical observation from EIA and PMAs is shown as a black line for comparison. The corresponding multimodel probability distributions of annual hydropower generation in the baseline and future periods are also compared in the right panel. A two-sample Kolmogorov-Smirnov test at the 5% significance level is used to determine if the difference between baseline and future periods is statistically significant.

The annual and seasonal changes in hydropower generation are further summarized in Fig. 5.11. The change in Fig. 5.11 is defined as the percentage difference (%) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of the box indicating the 25th and 75th percentiles, and the whiskers extending to the lowest/highest models. The monthly multimodel 10th, 50th, and 90th percentiles of generation and watershed storage are shown in Appendices H and I for further illustration.

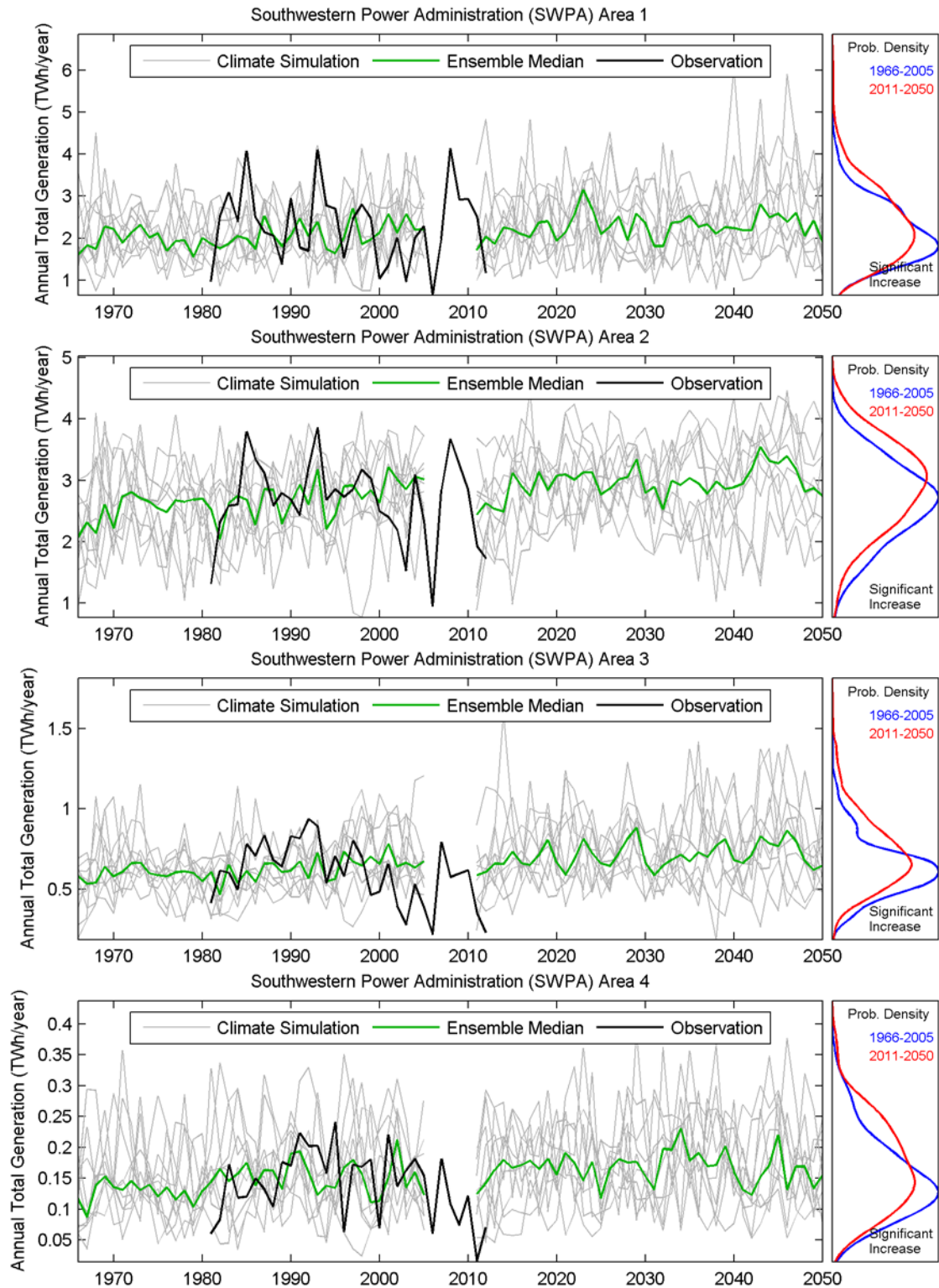


Fig. 5.10. Projected annual total generation in the Southwestern region.

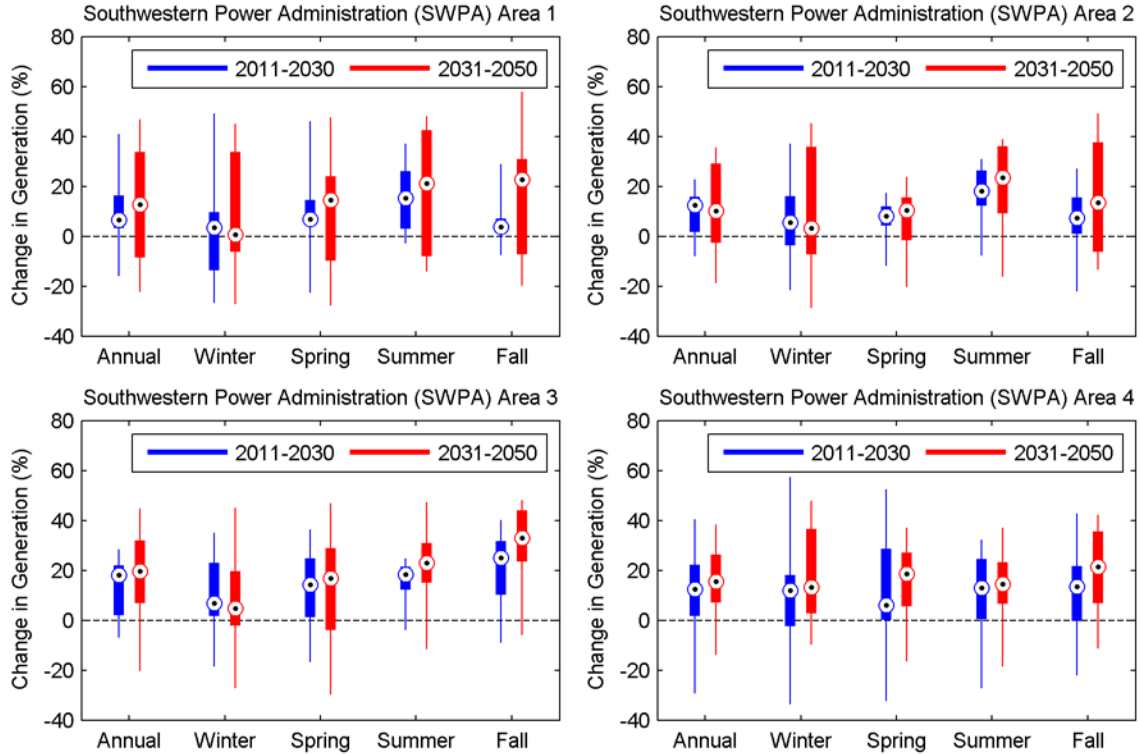


Fig. 5.11. Projected change of annual and seasonal total generation in the Southwestern region.

The WRES model was developed and calibrated using the 1981–2012 hydropower, hydrology, and meteorology data, so it can only simulate how a current and stable hydropower system (i.e., without significant change in installed capacity) may react to a change in different meteorological and hydrologic inputs. This corresponds to one special feature of the US federal hydropower system: since the 1970s, there has been limited change in the total installed capacity (Kao et al. 2015). This lack of change in the federal hydropower system resulted in a rather stationary generation of data that may enable the development of a simplified hydropower model such as EBHOM (Madani and Lund 2009 and 2010) or WRES. With the WRES’ model limitation in mind, the simulated 1966–1980 generation represents how a current (i.e., 1981–2012) hydropower system would respond to the simulated 1966–1980 runoff and precipitation. Therefore, the simulated 1966–1980 generation will not be able to reflect the expanded capacity during that period. It will only serve as a baseline for comparison to the future climate projections in this study.

In general, the change across all Southwestern study areas is more consistent relative to the large differences among Western study areas. Fig. 5.10 suggests that the future annual hydropower generation is projected to increase, and the difference between baseline and future generation is statistically significant. In terms of multimodel median annual generation (Fig. 5.11), an increase is projected in all of the four Southwestern study areas from +5% in SWPA-1 to +20% in SWPA-3 in the near-term future period, and from +18% in SWPA-1 to +23% in SWPA-3 in the midterm future period. The increasing annual hydropower generation trend is likely a direct consequence of the increasing annual precipitation (Fig. 5.4) and annual runoff (Fig. 5.6)

simulated in this study, which is more than that projected in the first 9505 assessment (Sale et al. 2012) based on the previous generation climate models. Nevertheless, the current hydropower simulation is based on the assumption of no major change in the hydroelectric capacity or operation in the future. If there are additional changes in project conditions not simulated in this study, such as degradation of the system (e.g., due to aging infrastructure) or a drastic change in operation, these findings on future annual hydropower generation may not hold.

It should also be noted that although both annual hydropower generation (Fig. 5.10) and annual temperature (Fig. 5.2) are projected to increase, there is no direct relationship between them. As discussed in other sections, hydropower is a favored source of electricity generation owing to its operational flexibility and lower maintenance costs (i.e., the “fuel” is generally free of charge and renewable). Therefore, when conditions allow, utilities will try to maximize the usage of hydropower before switching to other fuel-dependent energy sources to optimize revenue, especially during daily peak load periods. As a result, at the annual scale, hydropower generation is mainly controlled by water availability (runoff and precipitation) rather than temperature (Kao et al. 2015). Increasing temperature has a larger influence on the hydrologic cycle (e.g., snowmelt and evapotranspiration) and could alter the seasonal characteristics of runoff.

In terms of seasonal hydropower projection, the simulated change (Fig. 5.11) is very similar to the projected change of runoff (Fig. 5.7), with a higher increase in summer and a lower increase in winter. Unlike snowmelt-dominated systems such as Bonneville and Western, the watersheds in the Southwestern region are mainly controlled by precipitation. As a result, the variability of future precipitation plays the most influential role in Southwestern’s water availability and hydropower generation.

Another feature of Southwestern’s hydropower system is its relatively smaller water storage capacity, which results in a different hydropower-climate change response when compared to the larger storage systems in the Bonneville and Western regions. Without the existence of larger reservoirs (e.g., Hoover Dam and Lake Mead), the Southwestern hydropower projects have smaller storage capacity to absorb the runoff variation and hence are heavily governed by precipitation and runoff variability. Similar observations can also be made from the findings in other PMA study areas (Sections 3, 4, and 6). In general, hydropower projects in the Bonneville and Western regions possess a relatively higher storage capacity, so the magnitude of seasonal hydropower change is less than the magnitude of seasonal runoff change. Conversely, the hydropower projects in the Southwestern and Southeastern regions have less storage capacity, so the projected change of seasonal hydropower generation will follow the projected change of seasonal runoff more closely. For hydropower projects with even less storage capacity or that are purely operated in run-of-river mode, their response to runoff variability will be more direct and could be more vulnerable in the projected future climate conditions. Although the watershed storage in WRES is a conceptual variable and does not have a direct link to actual storage in reservoirs supporting federal hydropower plants, it is likely to be able to capture the characteristic of total storage in these two types of systems.

For federal hydropower in the Southwestern region, the most important climate change factor is the distribution of future precipitation. While this study projects increasing precipitation in the Southwestern region, the simulation of precipitation also involves larger climate model uncertainty (as opposed to the multimodel agreement on increasing temperature). The increasing

precipitation also implies a higher possibility of future flood events, and it may complicate the water resource management decision between flood control and hydropower generation. In addition, although Southwestern's hydropower generation is projected to increase in the near-term and midterm future, such findings are based on the assumption that there is no significant change in the future installed capacity and operation. The issues of aging infrastructures and indirect effects may reduce the system's ability to mitigate runoff variability, thus increasing the difficulty of future operation.

5.3.2 Climate Change Impacts on Federal Power Marketing

Impacts on Supply

During the last decade, Southwestern has experienced several episodes of drought. In 2006, generation from Southwestern's 24 plants was the lowest in the 1970–2012 period. Customers voluntarily agreed to receive less energy than the 1,200 hours established in their peaking power contracts, but even after these agreements, Southwestern spent \$67 million in replacement power. Those expenditures translated into a 14% rate increase for customers phased in over a three-year period (Coombes 2013). From May 2012 to February 2014, Denison Dam generated only about 20% of average due to low lake levels, and Denison customers agreed with Southwestern to receive less energy and store water for the summer months (SWPA 2014a and 2014b). Seeing drought as a periodic occurrence in its system, Southwestern has proposed in its FY2016 budget request to Congress to initiate a Purchased Power Drought Fund. If authorized, funds would be collected from customers in advance and set aside in a special Treasury account to be used during times of drought in order to avoid sudden rate spikes.

Along with the purchased power adder already included in the customers' power rates, the Purchased Power Drought Fund request is an indication that Southwestern views drought as a major contingency that must be considered. However, the frequency of dry years could change in the future. The projected changes in extreme runoff periods shown in Figure 5.9 suggest an increase in the probability of both low runoff (dry) and high runoff (wet) years..

As for generation, the WRES model projects an increase in the future annual hydropower quantities that would be marketed by Southwestern. The increase would be higher in the summer than in the winter but positive for all seasons. The generation projections from the WRES model assume that available generation capacity will stay at the same levels as in the recent past and that the amount of water displaced by competing uses will also remain close to what has been observed to date. However, both availability factors and water volumes displaced for other purposes have experienced significant changes over time that resulted in a decreasing trend in the capacity factor. Southwestern and its customers are concerned with the impact of those water reallocations on federal hydropower.

The generation projections from the WRES model assume that available generation capacity will stay at the same levels as in the recent past and that the amount of water displaced by competing uses will also remain close to what has been observed to date. However, both availability factors and water volumes displaced for other purposes have experienced significant changes over time that resulted in a decreasing trend in the capacity factor. Southwestern and its customers work together in trying to stop or even reverse that decline.

Two examples of storage reallocations that have diminished the volume of water available for hydropower production in Southwestern's Integrated System are the reallocation of reservoir storage at Lake Texoma to serve as Texas water supply and the reallocation of reservoir storage per the Water Resources Development Act of 1999 for the provision of minimum flows for sustaining tail water trout fisheries in the White River. In both of these cases, Southwestern is being compensated for the lost hydropower. In the Lake Texoma case, the USACE was required to pay credits to Southwestern equal to the replacement cost of hydropower lost. In October 2010, Southwestern started passing those credits through to customers receiving allocations from the Denison project. In the White River case, the losses are compensated by reducing the fraction of system project costs allocated to hydropower, versus other authorized purposes, and having to be repaid by Southwestern. Going forward, the Southwest Power Resources Association (SPRA), which represents the interests of Southwestern's customers, opposes reallocations of water supply storage for any purposes other than municipal and industrial use and demands full compensation for the capacity and energy lost due to reallocations that have already been authorized (SPRA 2015).

To take advantage of the projected increase in water availability for hydropower generation, the turbine-generator units need to be available to turn that additional water into electricity. The goals of the Jonesboro Memorandum of Agreement (MOA) signed by USACE, Southwestern, and Southwestern's customers in 1999 are to maintain reliability and improve efficiency in the fleet of projects marketed by Southwestern. The Jonesboro MOA was established to stop a trend of increased unplanned outages in the 1990s as appropriations of federal money to fund rehabilitation and upgrades decreased (Coombes 2013). Since 1999, Southwestern's customers have already invested \$338 million in nonroutine O&M and have committed to invest an additional \$1.3 billion between 2014 and 2044 to rehabilitate the 24 projects marketed by the PMA. The Jonesboro MOA was transitioned to a Customer Trust MOA in 2014.

Southwestern Customers' Impacts on Demand

The type of customers Southwestern serves and the season in which their demand peaks are important features in discerning the impact that projected temperature trends will have on their demand profile. All of Southwestern's customers are preference customers (i.e., cooperatives, municipalities, and government agencies) with large fractions of temperature-sensitive residential and commercial loads. Regarding seasonality, Southwestern is a summer peaking system. EIA Form 861 data for 2006–2013 show that summer peak demand for Southwestern was between 11% and 29% larger than the winter peak demand in each of those years.

According to the multimodel ensemble median discussed in Section 5.2, the mean temperature is projected to increase in all seasons. Increases in temperature would reduce electricity demand for heating during the winter months but would increase the demand for cooling during the summer months. As a result, the difference between summer and winter peak loads would become larger and peaking resources that could be deployed in the summer would become particularly valuable. An accurate estimation of changes in total electricity consumption and summer peak electricity demand by Southwestern's customers would require detailed information on their demand profiles and a statistical analysis to determine the responsiveness of demand to changes in temperature and other key drivers of electricity demand. Such a detailed analysis is out of the scope of this document, but existing literature provides useful information on the approximate

size of the temperature-induced electricity demand increases in the region where Southwestern's customers are located.

Dirks et al. (2015) estimate temperature-induced changes in building electricity consumption throughout the Eastern Interconnection using a decision support tool that combines climate model projections with a detailed simulation model of building energy use. For the West South Central Census division (Oklahoma, Texas, Arkansas, and Louisiana) in which Southwestern sold 58% of power in 2013, the estimated increase in summer peak demand is 14% by 2052 and 22.5% by 2089 relative to the 2005 baseline.⁴⁶ The study assumes that the characteristics of the building stock remain constant throughout the planning period. One of the building stock attributes that matters most for cooling electricity demand is the fraction of buildings that use air conditioning equipment. The most recent Residential Energy Consumption Survey (RECS) estimated that the percentage of homes using one or more types of air conditioning was very close to 100% in the region where Southwestern markets federal power (EIA 2009). Therefore, excluding the evolution of air conditioning saturation as a driver of cooling demand projections will not be an important omission for this particular region. On the other hand, improvements in the efficiency of cooling equipment or deployment of demand response programs could play a role in offsetting some of the projected increase in the summer demand peak.

The projected increases in summer peak demand among Southwestern's customer base do not translate into increased service obligations for the PMA because its mission is to market the available federal hydropower generation rather than to serve a specific fraction of its customers' demand. However, the changes in relative winter versus summer peak demands can affect Southwestern expenditures and operations. First, increases in summer peak demand could result in wholesale electricity price increases during the summer as the more inefficient generation units in the region would need to come online. Those higher prices would make any required wholesale power purchases during the summer months more expensive. Second, Southwestern's customers might begin to use more of their available allocation in the summer months. On average, from 2000 to 2012, spring (April through June) has the largest seasonal generation (33% of annual total) from the 22 plants form Southwestern's Integrated System due to the spring months being the largest inflow months into the reservoirs.

Impacts on Southwestern's Marketing

When climate-related impacts on Southwestern's supply (i.e., projected increases in generation that would be larger in the summer) and its customer's demand (i.e., increase in summer peak demand and decrease in winter peak demand) are taken together, the picture that emerges for the future average year shows favorable changes for the PMA and its customers relative to the average conditions in recent years. The projected average year would entail lower reliance on replacement power purchases by Southwestern and more supplemental power available to offer customers in addition to the 1,200 hours established in the peaking power contracts. Regarding power rates, the revenue from additional supplemental energy sales would help keep the peaking

⁴⁶ The rest of the energy was sold to preference customers in Missouri and Kansas. These two states belong to the West North Central Census division (along with North Dakota, South Dakota, Minnesota, Nebraska, and Iowa). Dirks et al. (2015) estimate an increase in peak demand of 44% in 2052 and 85% in 2089. Without further disaggregation at the state level and given the spread in heating degree days across the six states in that census division, it is not clear how representative those percentages would be for the cooling load of Southwestern's customers in Missouri and Kansas.

power rates stable while collecting enough revenue to repay the US Treasury. Moreover, to the extent that less replacement power purchases would be needed, the purchased power adder would decline. However, even if the precipitation trend is favorable for Southwestern, the projected increased probability of extreme runoff events in the region is equally important for the PMA's decisions about how to structure long-term contracts with their customers. Both Southwestern and its customers must be ready to manage more frequent flood and drought events over the life of those contracts.

Southwestern's contractual amounts (1,200 hours of peaking power) are based on delivery of power during the drought of record at each project. The 1,200 hours would be consistent with a capacity factor of 14%. On the other hand, the average capacity factor across the 22 plants that produce power marketed as part of Southwestern's Integrated System has been 26% for the 2000–2012 period. Only in 2006 was the actual capacity factor lower than needed to fulfill its 1200-hour peaking power contractual obligations. In that year, the capacity factor was 8%. For the rest of the years, Southwestern's Integrated System customers have had the option to purchase additional supplemental energy at the same energy rate as the contracted peaking power. On average, Southwestern provides more supplemental energy than peaking energy, and about half of the supplemental energy is provided during on-peak hours. Even if the projected increase in generation materializes, the risk of drought remains. Thus, the allocation of peaking power will likely be maintained and the proportion of total energy deliveries that are supplemental energy would increase.

Southwestern's Interaction with the Wholesale Market

The peaking power product currently offered by Southwestern will be most valuable to its customers if generation is scheduled (to the degree possible given all other purposes served by the project) during the seasons and hours in which wholesale prices are highest. The correlation between generation and wholesale prices offers an indication of the extent to which generation followed price signals. Fig. 5.12 displays the two series from 2008 through 2012 that are needed to compute that correlation: monthly hydropower generation marketed by Southwestern and monthly average price at the Southwestern Power Administration hub. These are generated as part of the SPP's EIM.

The correlation coefficient between Southwestern's monthly generation and the monthly average price at the SPP Southwestern Power Administration (SPA) hub between 2008 and 2012 was 0.547.⁴⁷ A host of operational rules and constraints associated with the multipurpose nature of federal water resource projects prevent this correlation from ever being close to 1. Water releases scheduled by USACE for flood control or environmental purposes are examples of those constraints. In recent years, the timing of generation by wind plants adds another consideration to hydropower generation scheduling decisions. The sign of the correlation coefficient is consistent with Southwestern selling most of its power as peaking power, with voluntary agreements between Southwestern and its customers to save stored water for when it is most valuable, with hydropower representing a very small portion of the electricity generation mix in the states

⁴⁷ From 2008 to 2012, SPP was functioning as an EIM rather than a RTO. The price in Figure 5.13 is a locational imbalance price, produced at five-minute intervals to resolve divergences between scheduled and actual energy, rather than the locational marginal price that a RTO would produce as the result of a centralized day-ahead dispatch of all generation resources in its territory.

where Southwestern operates. In the six states where Southwestern markets power (Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas), the fraction of total generation that came from hydropower in 2011–2013 was less than 5%. Thus, all else equal, years with more than average or less than average streamflow and hydropower generation do not have a significant effect on the wholesale price of electricity in the region.

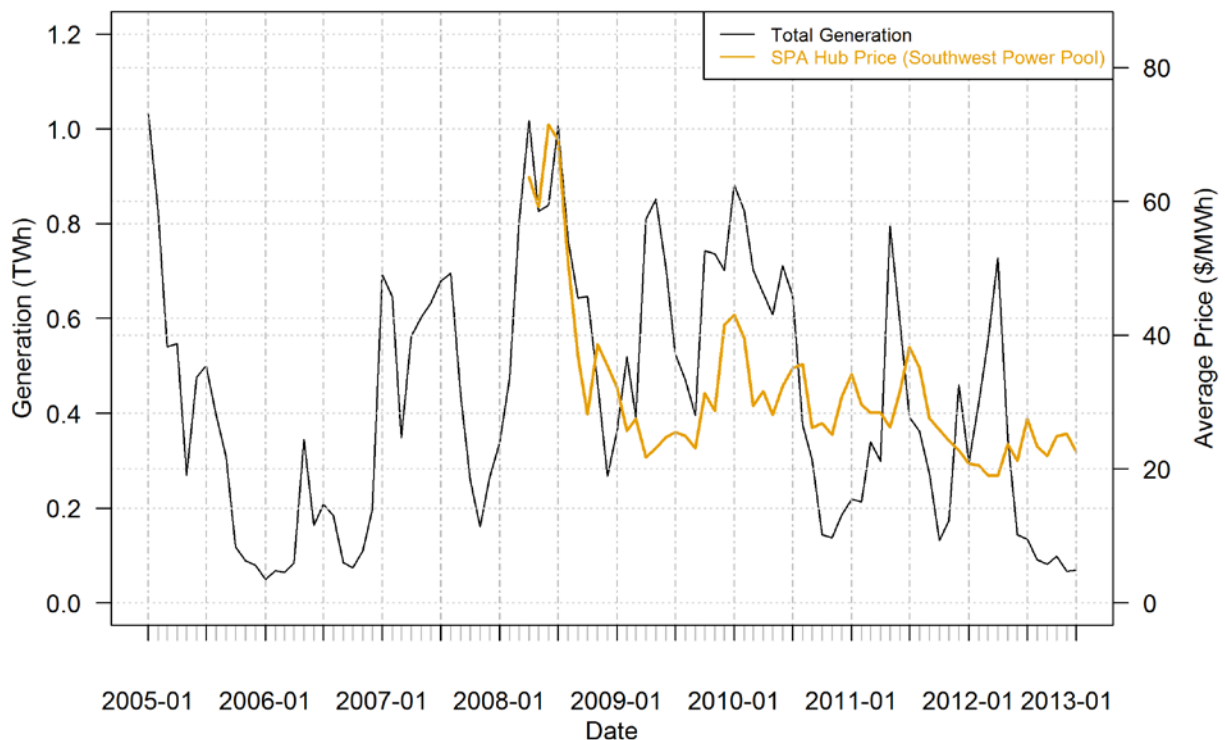


Fig. 5.12. Monthly hydropower generation marketed by Southwestern vs. monthly average wholesale price

Southwestern’s balancing authority area (denoted by the identifier “SPA”) is located within the footprint of the SPP RTO.⁴⁸ According to EIA Form 860 data, 70.6% of the installed capacity within the Southwestern’s balancing authority area at the end of 2013 was hydropower. The remaining capacity was thermal: natural gas (16.4%), coal (11.5%), and distillate fuel oil (1.5%). Southwestern’s balancing authority does not directly provide regulation and operating reserves for variable renewables as do some of the other balancing authorities managed by PMAs in the; however, as part of the SPP reserve sharing group, Southwestern can be impacted operationally by variable renewables in the region. All but two of the customers in the Integrated System are members of (or affiliated with) either SPP or MISO (Wech 2014). Wind represents 11.45% in the SPP and 7.7 % of installed capacity in the MISO footprint and is expected to increase in the future (SPP 2015, Potomac Economics 2014). Thus, the vast majority of Southwestern’s customers participates in markets with substantial volumes of variable renewables and follows the prices in those markets as they make their scheduling and purchasing decisions.

Just as temperature trends could cause Southwestern's customers to use more of their available peaking power allocation during the summer months, the increased penetration of renewables in

⁴⁸ SPP consolidated its 16 balancing authorities into a single one in 2014.

the SPP and MISO footprints also affects the timing of demand throughout the day. When abundant wind generation coincides with supplemental energy offers by Southwestern, the PMA might have difficulties finding a taker for that energy. To reduce the probability of oversupply situations in which water would have to be spilled, Southwestern works to schedule the supplemental energy one day in advance. Southwestern's customers prefer participating in the day-ahead market rather than the real-time market and will be more likely to purchase the supplemental energy if they know of their availability at the time in which they are making the rest of their scheduling and purchasing decisions (Wech 2014).

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6 THE SOUTHEASTERN REGION

Using the methodology described in Section 2, the assessment results for federal hydropower plants marketed through Southeastern Power Administration (SEPA or Southeastern) are summarized in this section. The study area definition, background hydropower, and marketing characteristics are described in the first subsection. The hydroclimate projections, along with a literature review of other hydroclimate studies in this region, are presented in the second subsection. The potential impacts on federal hydropower generation and risks on federal hydropower marketing are discussed in the third subsection.

6.1 Regional Characteristics

6.1.1 Study Areas

Southeastern markets hydroelectric power in ten southeastern states and southern Illinois (Fig. 6.1). Southeastern is the only PMA in the eastern US and contains no Reclamation projects. The 22 USACE hydropower plants in this region have a total installed capacity of 3,796 MW and an average annual generation of 7.7 TWh/year (NHAAP 2014). Considering the power system and watershed boundaries, the Southeastern is subdivided into four study areas:

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

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

The first study area, 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 mi², making it one of the smallest evaluated in the 9505 Assessment. Elevations range from 3,743 to 299 ft, with a median of about 700 ft. Dominant land cover types are cropland–natural vegetation mosaic (52%), deciduous broadleaf forest (32%), and mixed forest (8%), plus minor cropland (3%).

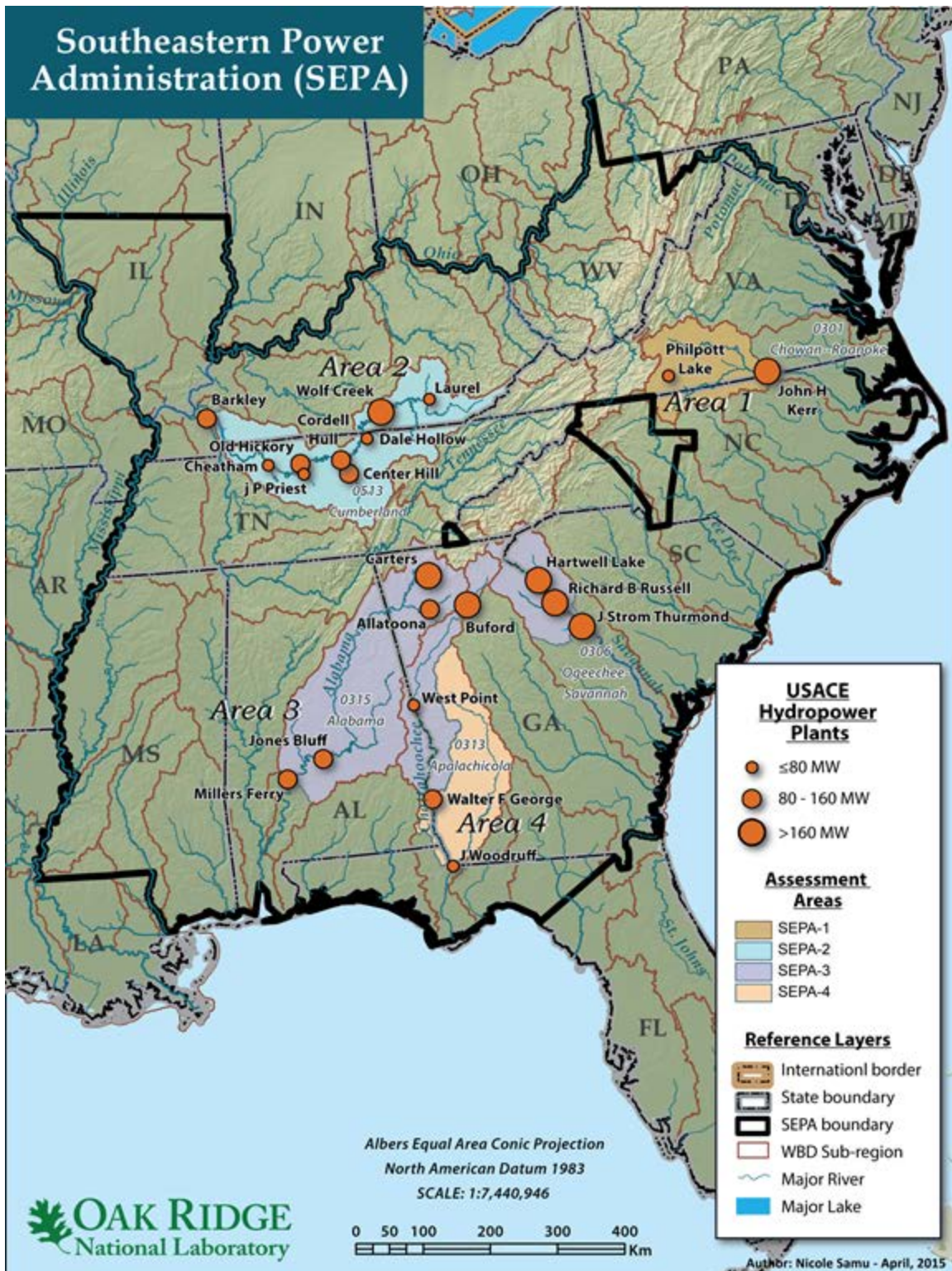


Fig. 6.1. Map of the federal hydropower plants and study areas SEPA 1-4 in the Southeastern region.

The second study 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 mi². Elevations range from over 4,000 ft in the eastern headwaters

to 300 ft at the Ohio River, with a median of approximately 900 ft. Land cover is a diverse mixture of deciduous broadleaf forest (39%), cropland–natural vegetation mosaic (36%), cropland (17%), and mixed forest (3%).

The third study area, 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 mi². Elevations range from over 5,000 ft to about 40 ft, from mountains in the northern end to the southern coastal plains. The median elevation of this area is 682 ft. 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 study area, SEPA-4, is defined by one small USACE hydropower project, the J. Woodruff project, located on the border between 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 mi², 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 in the Southeastern Region

All federal hydropower plants 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 remainder (24%) of Southeastern's power capacity (SEPA-2 area). Southeastern's two largest capacity hydropower plants are Richard B. Russell (628.0 MW) and Carters (500.0 MW). The smallest hydropower plants are J. Percy Priest (28.0 MW) and Philpott (14 MW). Two of the USACE hydropower plants in the Southeastern region have some reversible turbines that may allow for pump-storage operation (Richard B. Russell and Carters). A complete list of all of the federal hydropower projects in the Southeastern region can be found in Appendix B, which includes data on installed capacity and average annual generation from 1970–2012.

The oldest hydropower plants in this region are the Allatoona in SEPA-3 and the Center Hill in SEPA-2, each built in 1950. The newest hydropower project in the Southeastern region is Richard B. Russell on the upper Savannah River, which began operation in 1984. The average age of USACE hydropower projects in the Southeastern region is 35 years. Therefore, equipment modernization and refurbishment are also a common challenge for the federal hydropower plants in this region (Sale 2011).

Southeastern has some of the same water resources management challenges that occur in other parts of the US. 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 (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. Details on Southeastern's multipurpose water management issues can be found in Sale et al. (2012).

Table 6.1. Summary of federal hydropower plants in the Southeastern region

Area	Area name	Number of plants			Total installed capacity ^a (MW)	Average annual generation ^b (GWh/year)
		USACE	Reclamation	Total		
SEPA-1	Kerr-Philpott	2	0	2	311	471.0
SEPA-2	Cumberland	9	0	9	927	3,211.8
SEPA-3	GA-AL-SC	10	0	10	2,514	3,814.2
SEPA-4	Jim Woodruff	1	0	1	44	211.8
Total		22	0	22	3,796	7,708.8

^a Southeastern total nameplate capacity. Includes both conventional hydro and pumped storage.

^b Southeastern average annual generation from 1970 to 2012, conventional hydro only.

6.1.3 Power Marketing by Southeastern

Southeastern was established in 1950 as the PMA that would market the electricity from federal hydropower projects in the Southeast (with the exception of those managed by TVA). A general description of what a PMA is and how it conducts its mission is presented in Section 1.2.2. The Flood Control Acts of 1938, 1944, 1950, and 1966 authorized the construction of the 22 USACE multipurpose water resource projects for which power is currently marketed by Southeastern. Unlike the other three PMAs, Southeastern does not own any transmission assets. When Southeastern tried to obtain authorization from Congress to build new power lines, private utilities argued that there was already sufficient transmission infrastructure in the Southeast and that Congressional authorization would result in taxpayers having to pay back the cost of redundant infrastructure.⁴⁹ Since it does not own transmission lines, Southeastern contracts wheeling (i.e., transportation) services with other utilities to deliver power to its customers.

Southeastern markets power to 486 customers in 11 states. Except for one IOU (Florida Power Corporation), the remaining utilities are either public bodies or cooperatives. Marketing policies and rate schedules are set for four separate power systems: Cumberland, Georgia-Alabama-South Carolina, Kerr-Philpott, and Jim Woodruff. Southeastern markets the majority of its power as peaking power and all of its sales are through long-term contracts.

During its first decades of operation, Southeastern largely negotiated power allocations with each individual customer, gathering limited input from third parties that might be indirectly affected by the resulting agreement. When the Department of Energy Organization Act of 1977 transferred Southeastern from the Department of Interior to the DOE, it was directed to make the marketing policy negotiation a public process. The new procedure was applied in the development of marketing policies issued in 1980 (Georgia-Alabama-South Carolina system), 1983 (Cumberland system), and 1985 (Kerr-Philpott).

⁴⁹ <http://energy.gov/sites/prod/files/2013/07/f2/SEPAHistorySect1-cleanup1.pdf>

The marketing policies developed in the 1980s, which are still similar to those used today, introduced some significant changes. First, the number of preference customers served by the Cumberland system was expanded by extending eligibility beyond the traditional TVA service area. Second, Southeastern phased out the sales of “capacity without energy” to IOUs whose transmission assets were used to deliver the power to Southeastern’s customers. Through these transactions, the IOUs could schedule the power for delivery to preference customers at their convenience, and in exchange, they could reduce transmission rates charged to those preference customers (Vince and Wodka 1986). However, these sales were opposed by existing preference customers pursuing larger allocations as well as public utilities and cooperatives that did not yet contract any power with Southeastern.

Updates to the marketing policies of the two largest power systems were issued in 1993 (Cumberland) and 1994 (Georgia-Alabama-South Carolina). For the Cumberland system, an interim marketing plan has been in effect since 2007 to address the reduced generation availability due to repairs at the only two storage projects in the system: Wolf Creek and Center Hill. Repairs at Wolf Creek were completed in the spring of 2013, but they are expected to continue until 2017 at Center Hill dam. For the duration of this interim period, no dependable capacity is being marketed from the Cumberland system, and therefore, no capacity charge is being applied to Cumberland customers.

A summary of the most recent rate schedules is presented in Table 6.2. Even though the capacity and energy rates are the same for all customers within a system, transmission charges vary depending on which utility is providing the capacity and energy. Therefore, Southeastern posts separate rate schedules for customers depending on which utility’s transmission infrastructure is used to transport the power from the federal power plant to the customer.

Table 6.2. Southeastern rate schedule summary

	Capacity rate (\$/kW-month)	Energy rate (mills/kWh)	Energy services charge (\$/kW-month)
Georgia-Alabama-South Carolina	4.81	12.33	0.12
Kerr-Philpott	3.65	14.63	
Cumberland	NA	17.69	
(interim operating plan)			
Jim Woodruff	10.29	26.51	
(preference customers) ⁵⁰			

Note: 1 mill = \$0.001

Southeastern used to work with fixed five-year rate structures, and purchased power costs were included in the basic capacity and energy charges. During drought, financial deficits would accumulate that would not be recovered until the next time rates were adjusted. The Office of Management and Budget directed SEPA to recover purchased power costs from customers during the month when the purchase occurred.⁵¹ This change was introduced in the rate schedules for the four Southeastern systems from 2002 to 2011.

⁵⁰ For the IOU (Florida Power Corporation) receiving power from this project, the monthly rate for energy equals the calculated fuel cost savings for the utility.

⁵¹ <http://energy.gov/sites/prod/files/2013/09/f2/SEPA%20HistorySect2.pdf>

6.2 Future Climate in the Southeastern Region

This section presents the projections of Southeastern's future hydroclimate conditions. Projections based on the multimodel ensemble runs are summarized in terms of the mean annual and seasonal changes (i.e., spring, summer, fall, and winter) in temperature, precipitation, runoff and evapotranspiration for near-term future (2011–2030) and midterm future periods (2031–2050) as compared to the baseline period (1966–2005).

6.2.1 Regional Climate Projections

The projected annual temperature for baseline (1966–2005) and future periods (2011–2030 in near-term and 2031–2050 in midterm) are illustrated in Fig. 6.2, with gray lines showing the annual mean temperature from ten downscaled climate models for both 1966–2005 baseline and 2011–2050 future periods, the green line representing the multimodel median, and the black line showing the 1981–2012 historical temperature observation from Daymet. The corresponding multimodel probability distributions in the baseline and future periods are compared in the right panel. A two-sample Kolmogorov-Smirnov test at the 5% significance level is used to determine if the difference between baseline and future periods is statistically significant. The main use of this type of interannual plot is to visualize the range of variability and trend made by each model and to evaluate whether the projected trend and variability are consistent with historic observation. Since climate models are not meant to reconstruct the exact timing of the historic interannual and decadal variability, the model runs are not expected to fully follow historic interannual values. The same condition applies when interpreting similar interannual plots of precipitation, runoff, and generation.

The annual and seasonal changes of temperature are further summarized in Fig. 6.3. Change is defined as the degree difference (F) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of box indicating the 25th and 75th percentiles, and the whiskers extending to the lowest/highest models.

The observed and future projections in mean annual air temperature illustrated in Fig. 6.2 show a continuous increase since 1970. A large intermodel variability (Fig. 6.2) is projected, and it is a good example illustrating why a multimodel ensemble approach must be used to understand the overall picture. However, the probability distributions of multimodel mean annual temperature show a statistically significant warm shift for the 2011–2050 period in all SEPA areas (Fig. 6.2). Mean annual temperature in the Southeastern region is projected to increase by approximately 1.5 °F in the near-term future and 3.0 °F in the midterm period (Fig. 6.3). In SEPA-1 and SEPA-2, the near-term period shows more warming in the wintertime than in other seasons. In SEPA-3 and SEPA-4, summertime warming is the largest, followed in magnitude by winter, spring, and fall. The degree of projected annual and seasonal warming is generally similar in all four Southeastern study areas.

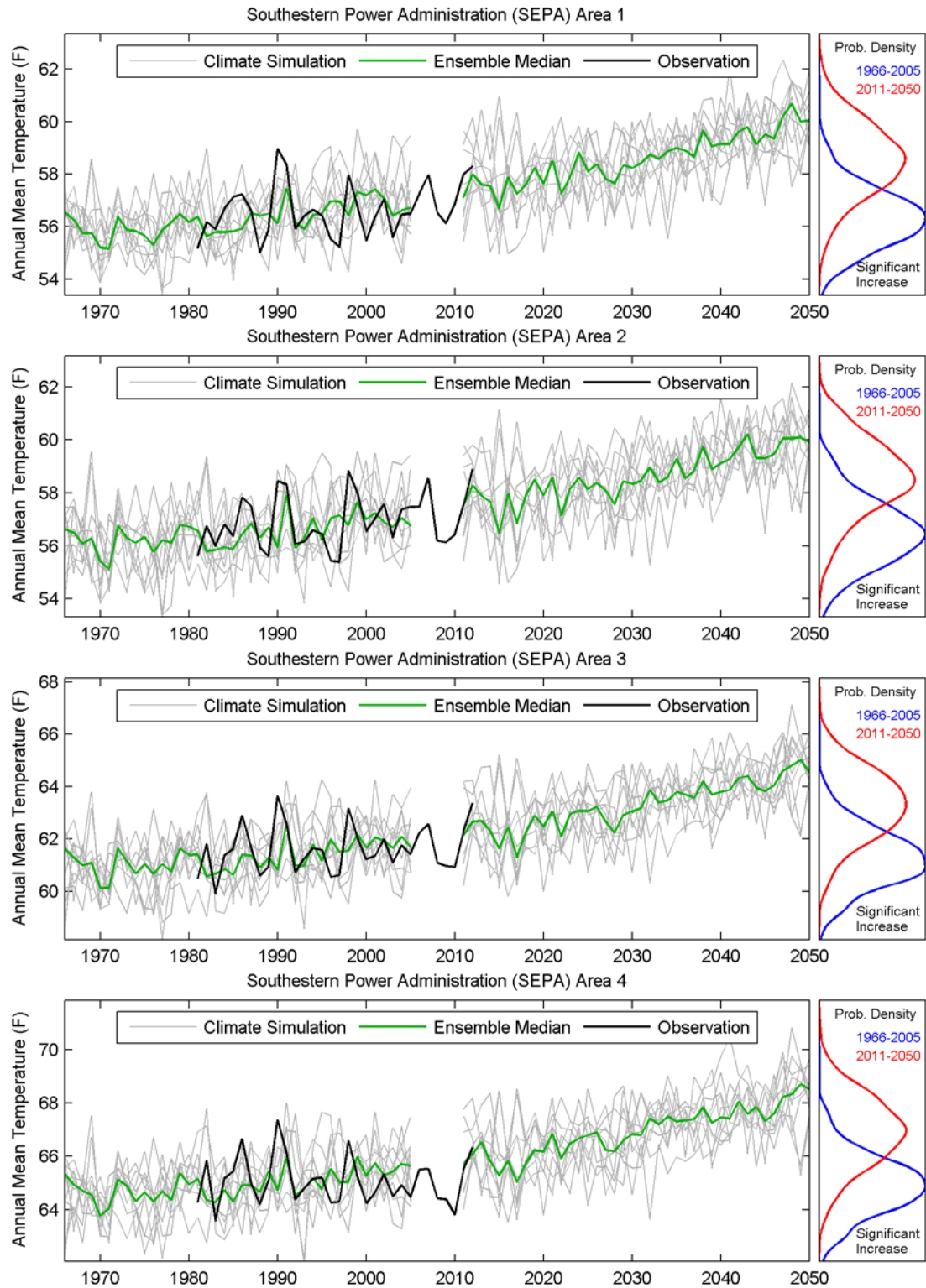


Fig. 6.2. Projected annual mean temperature in the Southeastern region.

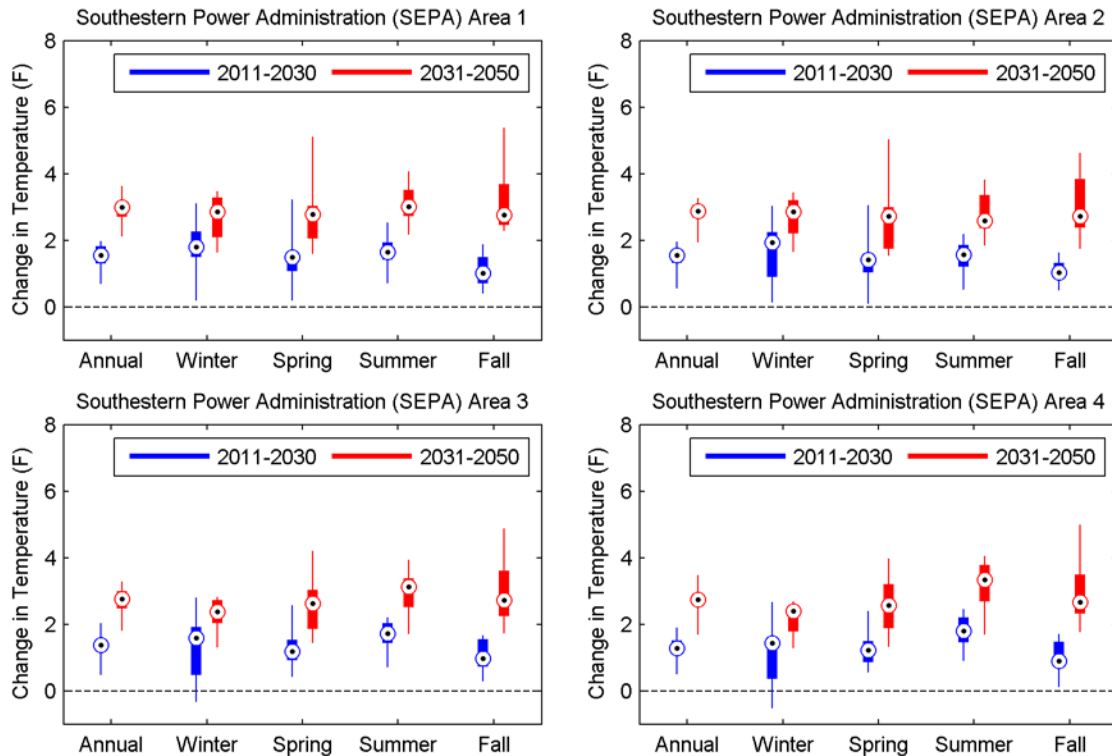


Fig. 6.3. Projected change of annual and seasonal mean temperature in the Southeastern region.

Similar to Fig. 6.2, the projected annual precipitation for baseline (1966–2005) and future periods (2011–2030 in near-term and 2031–2050 in midterm) are illustrated in Fig. 6.4. Because of large intermodel and interannual variability in mean annual precipitation, it is difficult to distinguish any long-term trend from changes in annual precipitation amounts. However, comparison of the probability distributions of the mean annual total precipitation shows a statistically significant increase in precipitation by the end of 2050 across all SEPA areas.

The annual and seasonal changes of precipitation are further summarized in Fig. 6.5, with change defined as the percentage difference (%) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of box indicating the 25th and 75th percentiles, and the whiskers extending to the lowest/highest models. The results do not show a clear and consistent pattern of changes in mean annual precipitation over Southeastern, and there is greater interannual and intermodel variability compared to the projected temperature changes (Fig. 6.4). There is little indication of change in mean annual precipitation, and the multimodel median suggests little or nearly no change. The model spread 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.

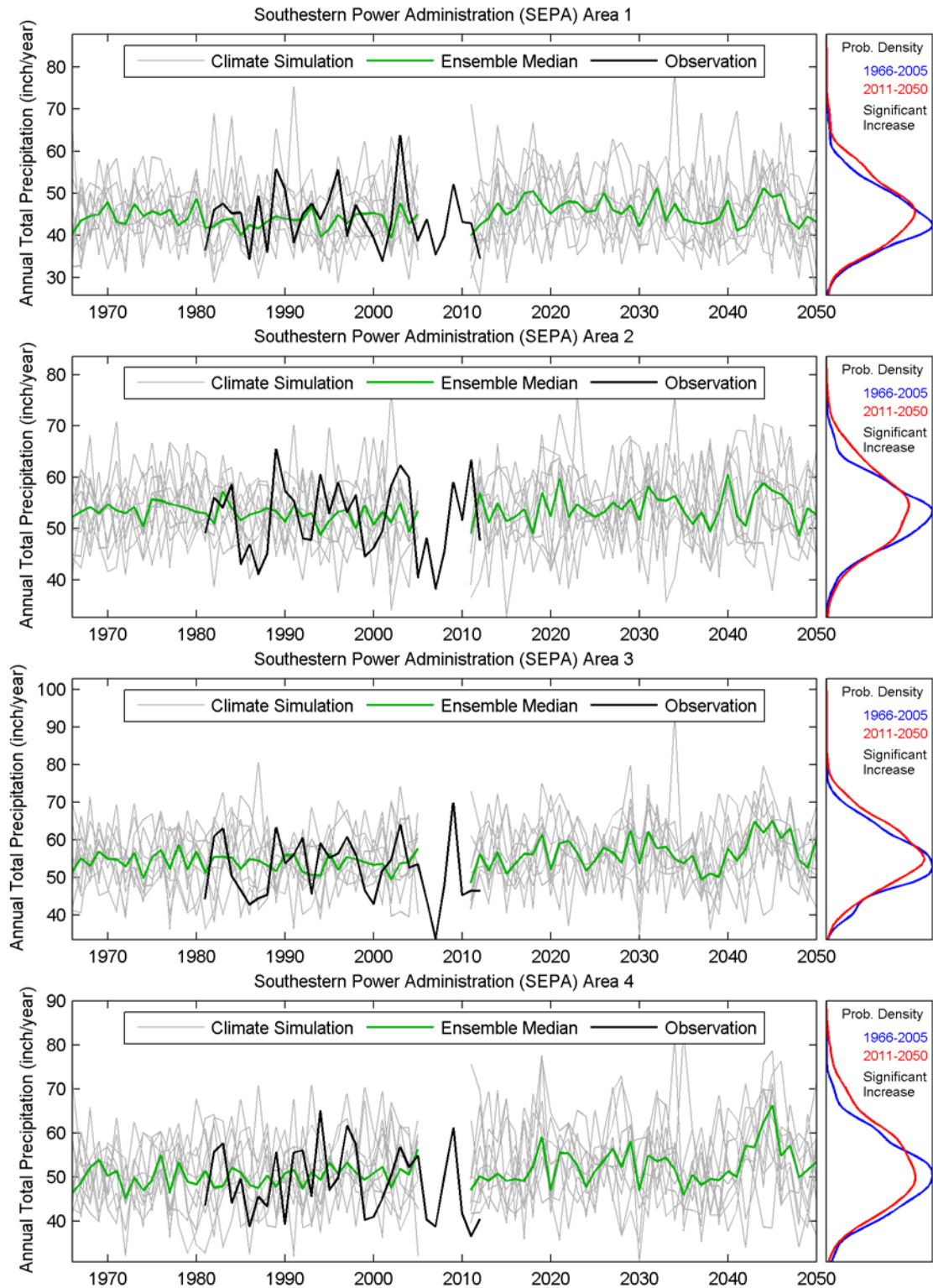


Fig. 6.4. Projected annual total precipitation in the Southeastern region.

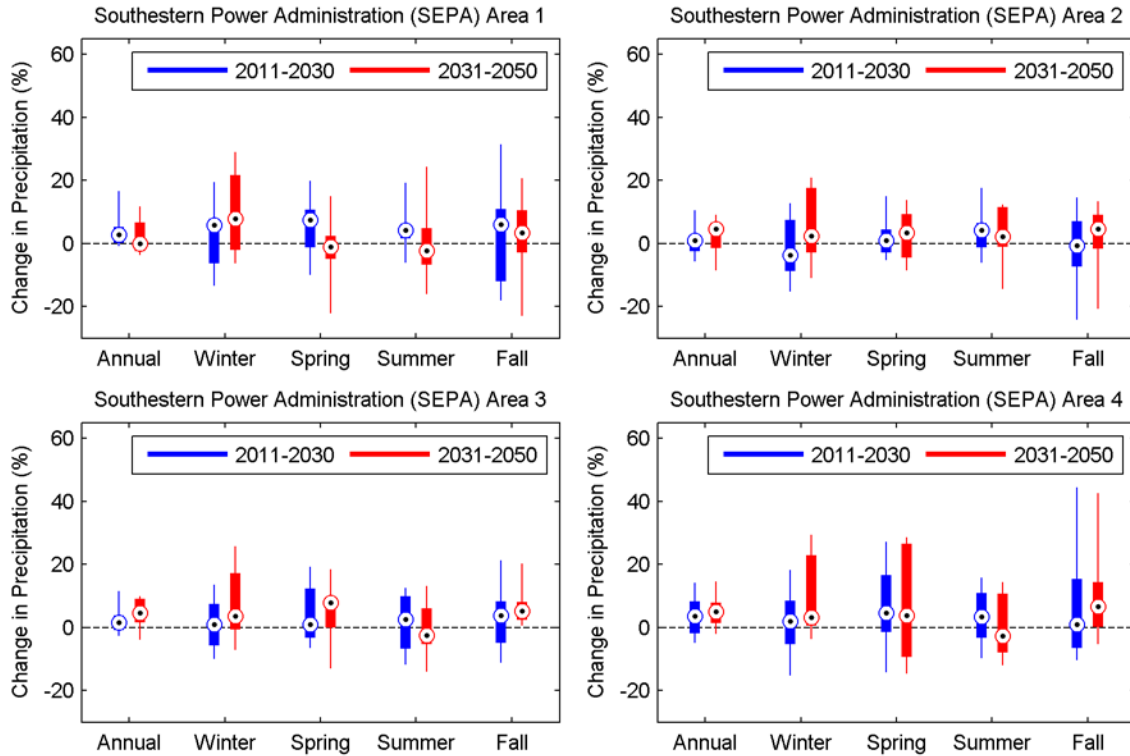


Fig. 6.5. Projected change of annual and seasonal total precipitation in the Southeastern region.

6.2.2 Regional Hydrological Projections

The runoff responses to projected climate show the projected mean annual total runoff for the 10 downscaled projections averaged spatially over each SEPA assessment area for both baseline (1966–2005) and future (2011–2030 and 2031–2050) time periods (Fig. 6.6 and Fig. 6.7). In Fig. 6.6, the gray lines show the annual total runoff from ten downscaled climate models for both 1966–2005 baseline and 2011–2050 future periods, and the green line indicates the multimodel median. The 1981–2012 historical observation from WaterWatch is shown as a black line for comparison. The corresponding multimodel probability distributions in the baseline and future periods are compared in the right panel. A two-sample Kolmogorov-Smirnov test at the 5% significance level is used to determine if the difference between baseline and future periods is statistically significant. The multimodel median and the mean of the historical VIC-simulated runoff values during the period from 1980 through 2012 are also shown.

In Fig. 6.7, the change is defined as the percentage difference (%) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of the box indicating the 25th and 75th percentiles, and the whiskers extending to the lowest/highest models.

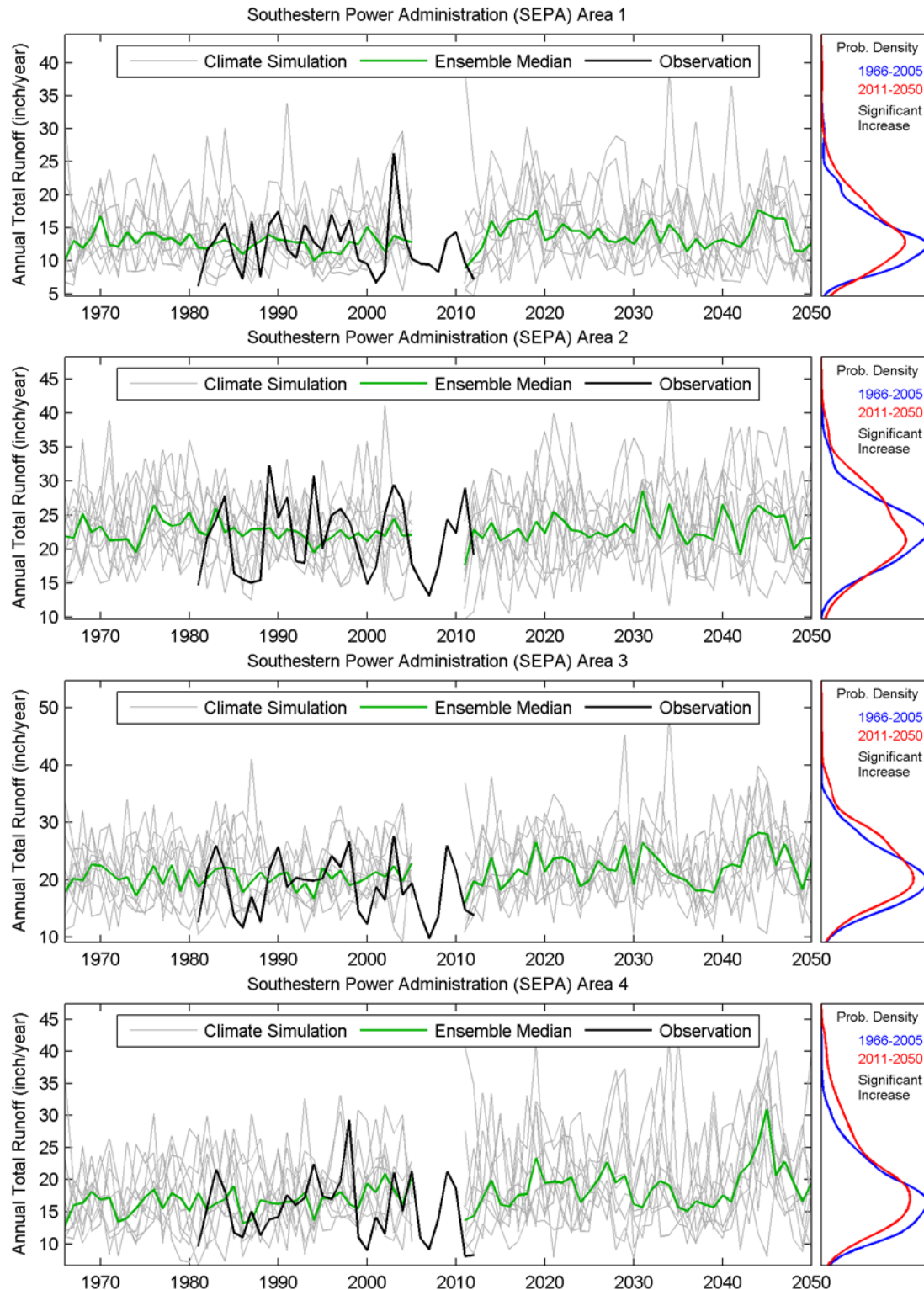


Fig. 6.6. Projected annual total runoff in the Southeastern region.

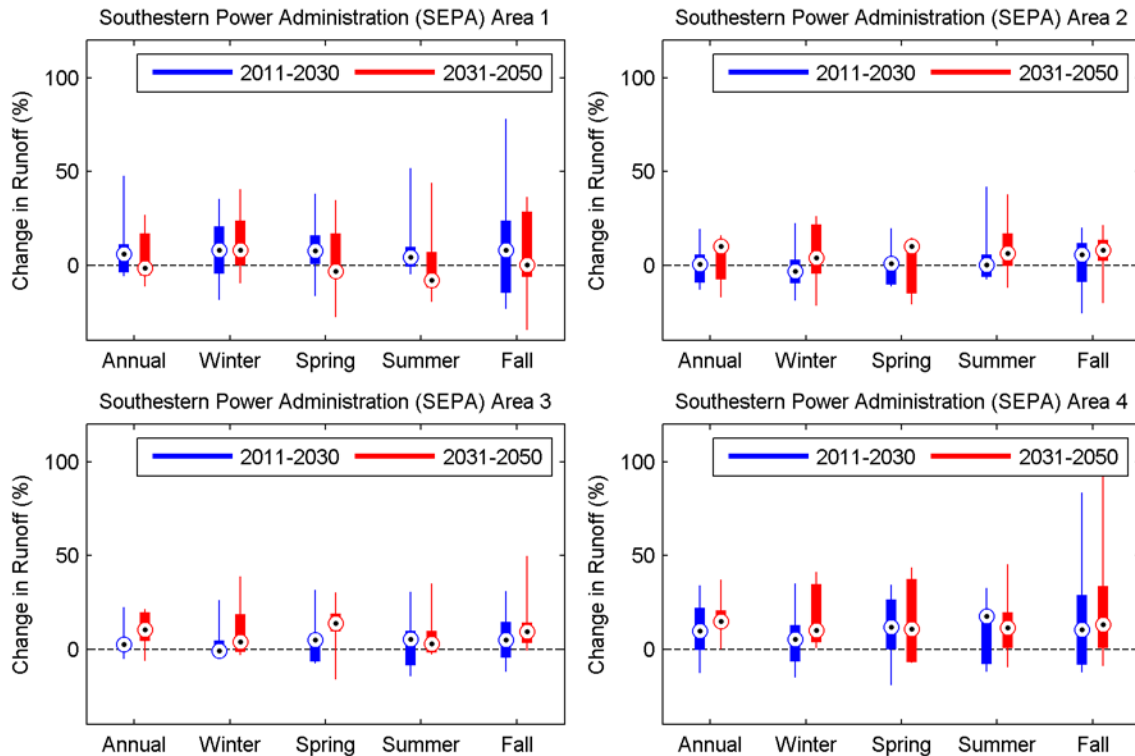


Fig. 6.7. Projected change of annual and seasonal total runoff in the Southeastern region.

Consistent with projected precipitation variability, the interannual variability in total runoff is high, and it is difficult to distinguish any trend from the annual variation in runoff amounts. The probability distribution in mean annual runoff in the future time period does show a significant increasing shift in runoff when compared with the baseline runoff distribution (Fig. 6.6).

The seasonal projections of runoff change in the Southeastern region show less clear patterns than the mean annual runoff changes (Fig. 6.7). The projected changes in runoff (in percentages relative to the 1966–2005 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 in SEPA-3 and SEPA-4, where there are slight increasing trends in annual and all seasonal runoff in the midterm time period. The runoff changes in SEPA-1 and SEPA-2 are less significant in all seasons. SEPA-1 shows a slight decreasing trend in spring and summer runoff by 2050, whereas for SEPA-2, an increase in runoff is projected by end of mid-century.

The projected increases in winter and spring runoff are also consistent with increases in precipitation and may contribute to an increase in wintertime evapotranspiration, as shown in Fig. 6.8. The change is defined as the percentage difference (%) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of box indicating the 25th and 75th percentiles, and the whiskers extending to the lowest/highest models.

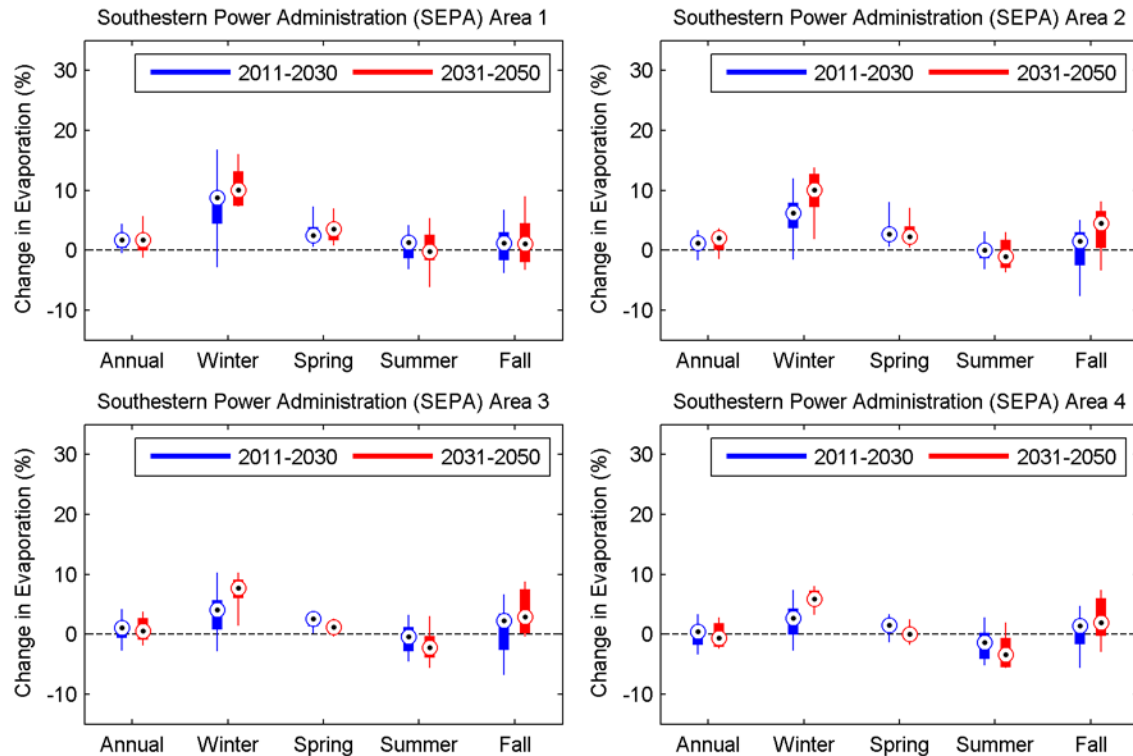


Fig. 6.8. Projected change of annual and seasonal total evapotranspiration in the Southeastern region.

An additional analysis of the extremes shows the future changes in ensemble median high runoff (i.e., 95th percentile of daily runoff) and median low runoff (i.e., 5th percentile of running 7-day average runoff) for both Southeastern future projection periods. For SEPA-1, a decrease in high runoff is projected by the end of midcentury (Fig. 6.9a and b). Similarly, a slight decrease in low runoff threshold (i.e., dry conditions intensify) is also projected in most areas of Southeastern for both future time periods. SEPA-1 is the only exception for which an increase in low runoff is projected (i.e., fewer dry conditions), particularly in the near-term period (Fig. 6.9c and d). However, the southern areas show increase in both high and low runoff, and the northern areas show decrease to no change for both high and low runoff.

6.2.3 Comparison with Other Climate Studies in the Region

Due to factors such as the differences in spatial domain (e.g., Southeastern's four study areas do not cover the entire southeastern US), GHG emission scenarios, climate models, definition of baseline and future periods, and downscaling and bias-correction approaches, the hydroclimate projections summarized in this study may not be directly comparable with findings from other available studies discussed below. Nonetheless, some qualitative statements and comparisons can be made.

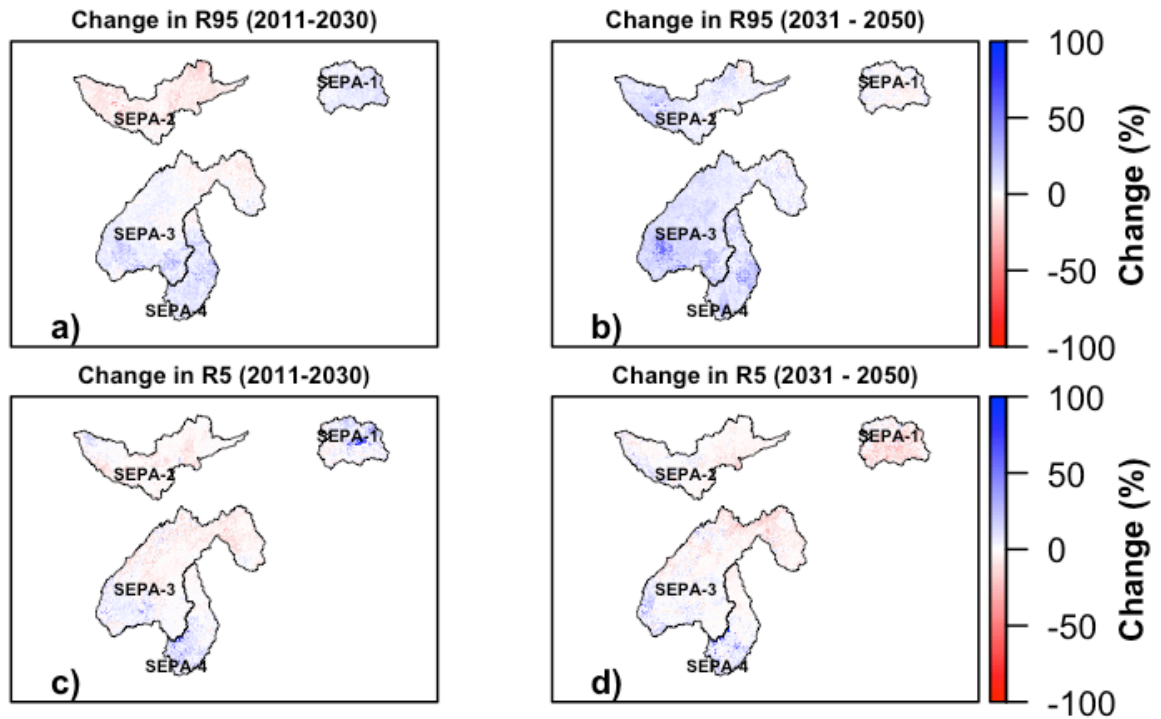


Fig. 6.9. Spatial distribution of multimodel ensemble median percentage change in (a) high runoff in 2011–2030, (b) high runoff in 2031–2050, (c) low runoff in 2011–2030, and (d) low runoff in 2031–2050 time periods in the Southeastern region.

Kunkel et al. (2013a) used the WCRP CMIP3 multimodel dataset (Meehl et al. 2007), statistically downscaled via Wood et al. (2002), to make projections for six large regions of the contiguous US as described in the third climate change assessment report. In addition to the CMIP3 models' projections, this study also used 11 GCM-RCM-based projections as part of the NARCCAP. They provided projections for each GCM-RCM combination simulation from 1971–2000, 1979–2004, and 2041–2070 for the high (A2) emissions scenario at a resolution of approximately 50 km for the Southeastern. Most CMIP3 models projections in this study show a positive change in mean annual temperature of 1.5 °F to 3.5 °F at the end of 2035 for both emission scenarios. For the 2055 future period, warming is projected in the range of 1.5 °F to 4.5 °F for B1 and about 3.5 °F to 5.5 °F for the A2 scenario. This study further shows that using the NARCCAP simulations, the simulated annual changes show projected warming in the range of 3 °F to 5 °F, with summer showing the greatest warming (3.5 °F to 6 °F). These results are generally consistent with the projections in this study with regard to the seasonal changes (i.e., projected warming is greater in summer than other seasons), but they differ a little in magnitude.

For precipitation, Kunkel et al. (2013a) show mostly a positive change using the NARCCAP simulations (i.e., about 9–12%). However, on a seasonal basis, summer shows mostly precipitation decreases, particularly to the north of Southeastern. Similarly, Liu et al. (2013) also show increases in winter and spring precipitation in 2055 relative to a recent historical baseline (1971–2000) for the South Atlantic Region. These results are similar to the projections in this study with regard to projected increases in winter and spring precipitation and a slight decrease in the summer precipitation for the midterm future time period (Fig. 6.5).

There are a limited number of climate projection studies evaluating changes in runoff for Southeastern. A recent study by Bastola (2013) (primarily Georgia and Florida) shows small increases in average spring and summer streamflow using various CMIP5 GCMs and different RCP scenarios. These results are generally consistent with the projections in this study, showing mostly increases in both spring and summer runoff, particularly in SEPA-3 and SEPA-4. 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 Apalachicola-Chattahoochee-Flint (ACF) systems. These coincide largely with SEPA-3 and SEPA-4. For precipitation, increases of +3% to +9% for 2020 and +3% to +13% for 2040 were projected. Average runoff ranged from -4% to +11% and -7% to +20% for these two decades. Both precipitation and runoff are slightly wetter than the projections made in this 9505 assessment. The authors concluded that on the whole, precipitation changes 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. Some further comparison of this assessment’s projections and the Brekke et al. (2013) CMIP5 projections is illustrated in Appendix C.

6.3 Climate Effects on Federal Hydropower in the Southeastern Region

This subsection discusses how the projected hydroclimate change may affect Southeastern’s federal hydropower generation. The projected change of annual and seasonal generation is presented in Section 6.3.1. The potential risk to hydropower marketing is discussed in Section 6.3.2.

6.3.1 Projections of Hydropower Generation

Using the WRES model described in Section 2.5, Southeastern’s monthly generation and watershed storage projections are calculated for each of the ten downscaled climate models. Projections based on multimodel ensembles are summarized in terms of the mean annual and seasonal changes (i.e., spring, summer, fall, and winter) for the near-term future (2011–2030) and midterm future (2031–2050) periods as compared to the baseline period (1966–2005).

The interannual variability of annual hydropower generation for the baseline (1966–2005) and future periods (2011–2050) is shown in Fig. 6.10, with gray lines showing the annual total generation from ten downscaled climate models for both 1966–2005 baseline and 2011–2050 future periods, the green line representing the multimodel median, and the black line showing the 1981–2012 historic observation from EIA and PMAs for comparison. The corresponding multimodel probability distributions of annual hydropower generation in the baseline and future periods are also compared in the right panel. A two-sample Kolmogorov-Smirnov test at the 5% significance level is used to determine whether the difference between baseline and future periods is statistically significant.

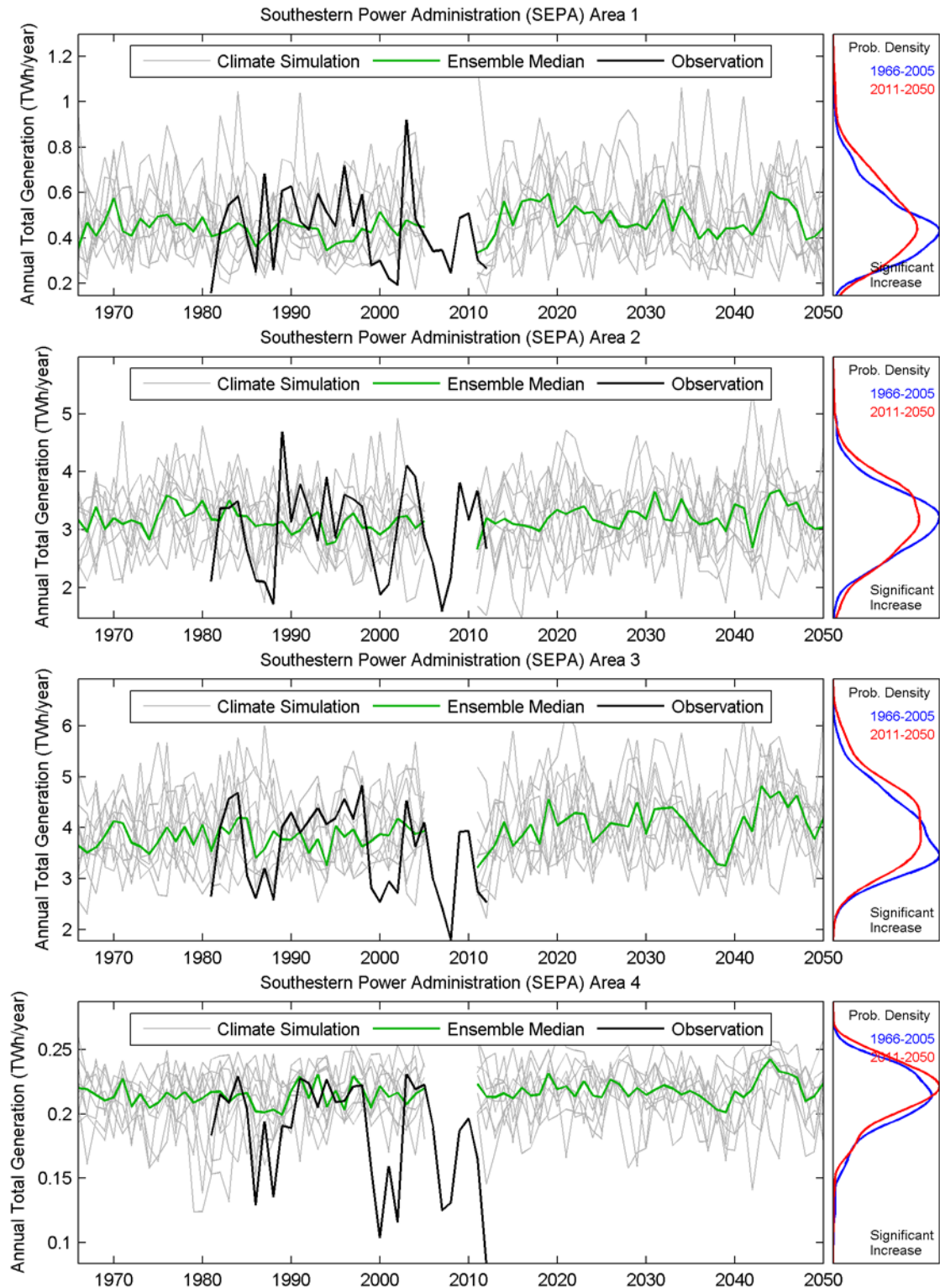


Fig. 6.10. Projected annual total generation in the Southeastern region.

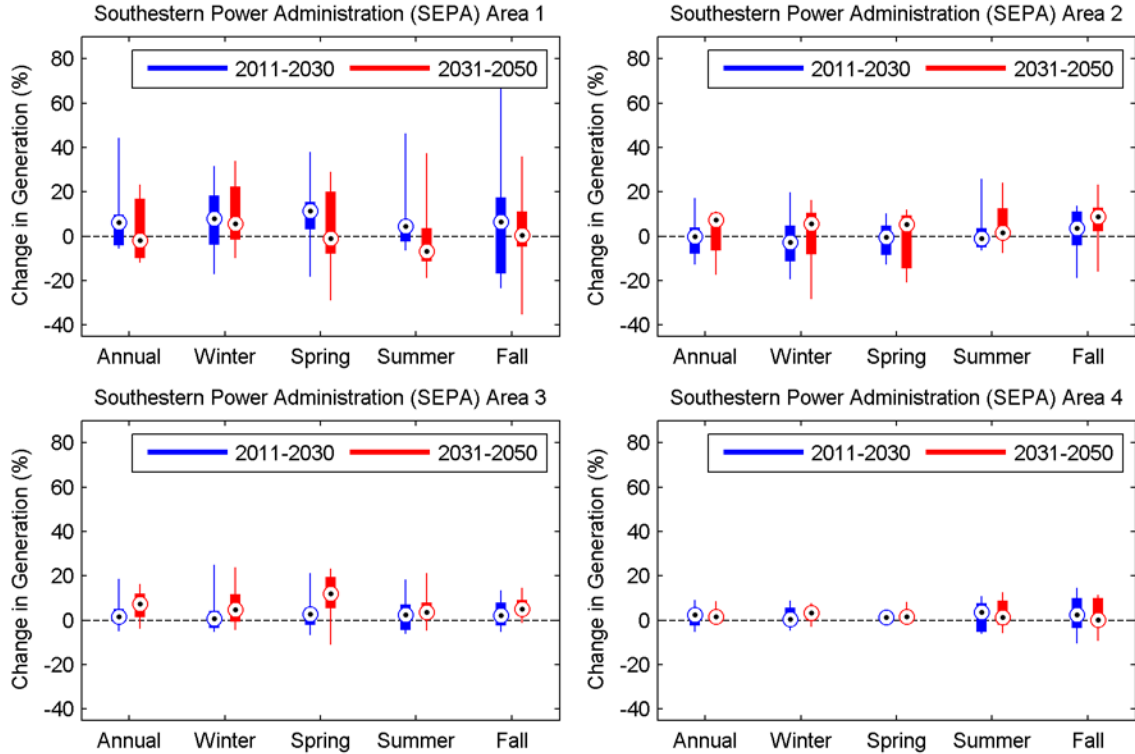


Fig. 6.11. Projected change of annual and seasonal total generation in the Southeastern region.

The annual and seasonal change of hydropower generation is further summarized in Fig. 6.11. The change in Fig. 6.11 is defined as the percentage difference (%) of future periods (2011–2030 and 2031–2050) compared to the 1966–2005 baseline period. Each box plot shows the spread across ten climate models, with the central mark indicating the multimodel median, the edges of box indicating the 25th and 75th percentiles, and whiskers extending to the lowest/highest models. The monthly multimodel 10th, 50th, and 90th percentiles of generation and watershed storage are shown in Appendices H and I for further illustration.

It should be noted that the WRES model is developed and calibrated using the 1981–2012 hydropower, hydrology, and meteorology data, so it can only simulate how a current and stable hydropower system (i.e., without significant change of installed capacity) may react to change of different meteorological and hydrologic inputs. This corresponds to one special feature of the US federal hydropower system: since the 1970s, there has been limited change of the total installed capacity (Kao et al. 2015). This lack of change in the federal hydropower system resulted in a rather stationary generation data that may enable development of a simplified hydropower model such as EBHOM (Madani and Lund 2009 and 2010) or WRES in this study. With WRES' model limitations in mind, the simulated 1966–1980 generation represents how a current (i.e., 1981–2012) hydropower system would respond to the simulated 1966–1980 runoff and precipitation. Therefore, the simulated 1966–1980 generation will not reflect the expanded capacity during that period. It will only serve as a baseline for comparison to future climate projection in this study. While the overall Southeastern results fit into the general expectation, SEPA-4 is among the two areas with the least reliable WRES modeling performance (Section 2.5). Therefore, the seasonal hydropower projection made for SEPA-4 is subject to a much larger modeling bias.

Similar to Southwestern, the change across all of Southeastern's study areas is more consistent when compared to the large difference among Southeastern study areas. Fig. 6.10 suggests that the future annual hydropower generation is projected to increase, and the difference between baseline and future generation is statistically significant. In terms of multimodel annual generation, the change in the Southeastern region is small. Most of the change is less than 8% in all Southeastern study areas and for two future projection periods. The increasing annual hydropower generation trend is likely a direct consequence of the increasing annual precipitation (Fig. 6.4) and annual runoff (Fig. 6.6) simulated in this study. Nevertheless, unlike the wetter trends projected in the Southwestern region, the projected precipitation, runoff, and hydropower are generally consistent with the previous 9505 assessment (Sale et al. 2012). The current hydropower simulation is based on the assumption of no major change in the hydroelectric capacity or operation in the future. If there are more changes in the climate conditions than simulated in this study, degradation of the system (e.g., due to aging infrastructure), or drastic change of operation, such findings on future annual hydropower generation may not hold.

Although an increasing trend in future annual temperature is observed (Fig. 6.2), it cannot be attributed to the increasing trend in future annual generation in Fig. 6.10. This can be explained by another feature of hydropower. Despite higher capital costs, hydropower can produce cost-competitive electricity with negligible fuel costs, and it responds rather quickly to load, depending on the timing and magnitude of electricity demanded. Therefore, when conditions allow, utilities will work to fully utilize hydropower before switching to other fuel-dependent energy sources at higher costs to optimize revenue, especially during daily peak load periods. Given that the usage of hydropower is constantly maximized, the total annual hydropower generation will be mainly controlled by water availability (precipitation and runoff) rather than energy demand, because those factors are more sensitive to temperature variation (Kao et al. 2015).

While there is a larger multimodel spread of future hydropower projection in some seasons and in some study areas (e.g., fall in SEPA-1 and winter in SEPA-2), the projected seasonal percentage change is relatively minor when compared to other PMA study areas. This corresponds to our understanding that the projected climate change signal is relatively weaker in the southeastern US. Similar to the Southwestern system, the projected change in annual and seasonal hydropower generation also follows the projected change of runoff closely (Fig. 6.6).

Unlike snowmelt-dominated systems such as Bonneville and Western, the watersheds in the Southeastern region are mainly controlled by precipitation. As a result, the variability of future precipitation plays the biggest role in Southeastern's water availability and hydropower generation. Another unique feature of Southeastern's hydropower system is its relatively smaller water storage capacity, resulting in a different hydropower-climate change response when compared to the larger storage systems in the Bonneville and Western regions. Without the existence of larger reservoirs (e.g., Hoover Dam and Lake Mead), Southeastern's smaller hydropower projects have a smaller storage capacity to absorb the runoff variation and hence are heavily governed by precipitation and runoff variability.

Similar observations can also be made from the findings in other hydropower study areas (Sections 3, 4, and 5). In general, hydropower projects in the Bonneville and Western regions have comparatively larger storage, so the magnitude of seasonal hydropower change is less than

the magnitude of seasonal runoff change. Conversely, the hydropower projects in the Southwestern and Southeastern regions have less storage capacity, so the projected change of seasonal hydropower generation will follow the projected change of seasonal runoff more closely. For hydropower projects with even less storage capacity or that are purely operated in run-of-river mode, their response to runoff variability will be more direct and could be more vulnerable in projected future climate conditions. Although the watershed storage in WRES is a conceptual variable and does not have a direct link to the actual storage in the reservoirs supporting federal hydropower plants, it is able to capture the characteristic of watershed storage in the regional hydropower systems.

For Southeastern's federal hydropower, the most important climate change factor is the distribution of future precipitation. While this study projects increasing precipitation for Southeastern, the simulation of precipitation also involves larger climate model uncertainty as opposed to the multimodel agreement on increasing temperature. The increasing precipitation also implies a higher possibility of future flood events, and it may complicate the water resource management decision between flood control and hydropower generation. In addition, although Southeastern's hydropower generation is projected to increase in the near-term and midterm future, such findings assume that there is no significant change in the future installed capacity and operation. The issues of aging infrastructures and indirect effects may reduce the system's ability to mitigate runoff variability and could result in future operational difficulties.

6.3.2 Climate Change Impacts on Federal Power Marketing

In order to explore how the climate projections presented in Section 6.2 affect power marketing, it is necessary to keep in mind the correspondence between Southeastern's study areas (SEPA-1 through SEPA-4) and the power systems for which the PMA develops marketing plans and sets rates. SEPA-1 contains the two projects marketed as part of the Kerr-Philpott system. The two largest power systems, Cumberland and Georgia-Alabama-South Carolina (GA-AL-SC), correspond to the SEPA-2 and SEPA-3 regions respectively. Finally, the Jim Woodruff project is located in the SEPA-4 region.

Section 6.2 presents temperature, precipitation, runoff, and generation projections for the Southeastern territory. Since the Southeast receives the majority of its runoff from precipitation rather than snowmelt, changes in precipitation have the most direct effect on the federal hydropower supply that the PMA markets. Meanwhile, changes in temperature may alter the magnitude and timing of peak demand and total electricity demand from Southeastern's customers.

Impacts on Supply

The climate model projections analyzed in this study indicate a statistically significant increase in precipitation by the end of 2050 in all four Southeastern areas. Summers are projected to be drier, but the decrease in summer precipitation would be offset by increases during the remainder of the year. Annual change in generation is projected to be positive but small (less than 8%). However, there is significant dispersion across the rainfall projections from the various climate models, especially during the summer and winter in the GA-AL-SC and Jim Woodruff systems.

The flexibility already built into Southeastern's power rates and contracts is an important attribute to manage the uncertainty associated with current projections.

The PMAs evaluate the probability of extreme years, either droughts or floods, when developing their long-term marketing strategies. Since many of the USACE projects in the region were built with flood control as one of their objectives, operational rules have long been in place to mitigate flood events. Conversely, drought plans have not been as well developed, but they will become increasingly important tools to balance out the ability to manage both types of extreme events (ACF Stakeholders, 2015).

The generation projections from the WRES model assume that available generation capacity will remain the same and that the amount of water displaced by competing uses will also remain close to what has been observed. However, both water volumes displaced for other purposes and availability factor have experienced significant changes over time in federal hydropower projects located in the Southeast.⁵² Southeastern and its customers can control to some extent the evolution of the availability factor at the federal hydropower plants by contributing funds for refurbishing and upgrading projects. As for changes in water allocations, those decisions are largely out of the hands of the PMA and its customers.

Customer funding agreements between Southeastern, its customers, and USACE have been put in place in all the power systems (except Jim Woodruff) since they were authorized by Section 212 of the Water Resources Development Act of 2000. The purpose of the customer funding agreements is to complement declining appropriations of federal money for funding the capital investments needed to attain performance and reliability objectives at federal hydropower units in the region. Outages made the availability factor of federal hydroelectric plants in the Southeast decline from 95% in 1987 to 87% in 1995 due to aging equipment and issues with initial equipment design at some of the projects (GAO, 1996). In addition, the designation of the Wolf Creek and Center Hill dams as high risk in 2007 drew attention to reliability concerns in the Cumberland system.

The Alabama-Coosa-Tallapoosa (ACT) and ACF basins in which the GA-AL-SC and Jim Woodruff systems are located are a salient example of the complexities involved when managing multiple water demands in a system of interconnected rivers and reservoirs. Droughts in the 1980s led to the Tri-State Water Wars between Georgia, Alabama, and Florida, resulting in prolonged litigation regarding allocation of water in the two basins. In the northern part of the ACF basin, municipal and industrial use water demands to serve the Atlanta metropolitan area have continuously increased since the federal hydropower projects were built. The southern part of the ACF basin supports irrigation needs for agriculture and provides environmental flows to ensure protection of threatened and endangered fish and mussel species. In addition, Florida depends on ACF flows to support its seafood industry, and Alabama withdraws water from the Chattahoochee for cooling a nuclear plant (Hamilton 2008, Miller 2014).

Disputes over the allocation of ACT/ACF water continue today and into the future. A 2011 court decision determined that USACE needed to balance power production with water supply at Lake Lanier. An update by USACE of the water control manual that outlines operational rules for

⁵² Availability factor is the percentage of hours in a year in which a turbine-generator unit is available for operation.

projects in the ACF basin will address that court decision and is expected in 2017. For the ACT basin, USACE completed an update of the water control manual in 2015. In November 2014, the Supreme Court announced that it will hear the case of Florida against Georgia related to allocation of waters in the ACF basin. To the extent that it changes water allocations or the timing of water releases in the basins, this litigation will impact the availability and timing of federal hydropower supply in the GA-AL-SC and Jim Woodruff systems.

Impacts on Demand by Southeastern Customers

The type of customers Southeastern serves and the season in which their demand peaks are important features in discerning the impact that projected temperature trends will have on their demand profile. All but one of Southeastern's customers are preference customers (e.g., cooperatives, municipalities) with large fractions of temperature-sensitive residential and commercial loads. Regarding seasonality, historical peak load data for utilities in the five states that receive most of Southeastern's sales—Georgia, Alabama, South Carolina, Kentucky, and Tennessee—reveal a summer peaking system during most years. Summer peak load in the three GA-AL-SC states was, on average, 8.6% greater than winter peak load during that period. Cumberland was also a summer peaking system. The average summer peak load in Kentucky and Tennessee was 3.9% greater than the average winter peak load. Section 6.2 results indicated that the mean annual temperature in the Southeastern region is projected to increase by approximately 1.5 °F to 3.0 °F in the near term (2011–2030) and midterm (2031–2050) periods respectively. The seasonal distribution of the temperature increase changes between the two projection periods considered. In the near-term, projected warming in the wintertime is stronger than in the other seasons. In the midterm, summertime warming is projected to exceed that of all other seasons.

Peak summer demand relative to the winter peak demand will tend to increase, due to increasing temperatures. In the near-term period, the projected dominant effect is winter warming which would reduce the size of the winter peak. In the midterm period, summer temperatures are projected to increase more than those in other seasons which would increase the size of the summer peak. Increased winter temperature will likely have a stronger effect on the winter peak demand from Southeastern's customers than for the other PMAs, because the fraction of residential load using electricity rather than natural gas for heating is significantly larger than in the other regions where PMAs operate. According to data from the latest RECS, the fraction of homes using electricity for space heating is 63% in the South Atlantic Census Division and 55% in the East South Central Division. In contrast, the US average is 36%. However, reliance on electricity is greater for cooling than heating. All air conditioning equipment uses electricity, and the saturation rates of air conditioning equipment estimated by RECS are 95% for the South Atlantic Census division and 97% for East South Central Census division.

The increases in summer peak demand that are expected among Southeastern's customer base do not translate into increased service obligations for the PMA because its mission is to market the available federal hydropower generation rather than to serve a specific fraction of its customers' demand. However, the changes in relative winter versus summer peak demands can affect Southeastern expenditures and operations. First, increases in summer peak demand could result in wholesale electricity price increases during the summer as the more inefficient generation units in the region would need to come online. Those higher prices would make any required

wholesale power purchases during the summer months more expensive. Second, Southeastern's customers might desire more of their energy allocation to be shifted to the summer months.

Impacts on Southeastern's Marketing

Given that Southeastern sells most of its power as peaking power, its customers would like to have the power available during summer peak load times. However, due to hydrology and project characteristics, winter is the season in which the segment of the federal fleet marketed by Southeastern generates the most electricity. On average, from 2000 to 2012, 39% of total generation took place in the months of December through March.⁵³ Moreover, increases in precipitation are projected to happen outside of the summer season. Shifting generation from winter to summer would be valuable for Southeastern's customers, but USACE's ability to change its operations to accommodate that preference is severely limited by the other purposes it serves (e.g., flood control) and by the limited reservoir storage capacity of federal projects in the region. With limited capability to shift generation across seasons, the projected changes in generation and peak demand would tend to increase the volume of replacement power purchases needed in summer and the volume of surplus power sales during the winter months.

The potential changes to generation outlined by the climate model projections would not impair Southeastern's ability to provide federal hydropower to preference customers at cost-based rates. If generation patterns at federal projects do not match the demand profiles of Southeastern's customers, the customers would have to procure additional peaking resources to make up for the discrepancy. Since procuring those alternative peaking resources takes time, customers will benefit from having as advanced notice as possible of changes in hydrology that might change the volume or timing of their allocations. In addition, given that the costs of replacement power are passed through to customers in the month in which they take place, customers would also bear any financial burden associated with increased replacement power purchases. The biggest concern for Southeastern would be if prolonged drought and the reduced ability to fulfill its customers' peaking demands would render federal hydropower no longer competitive relative to alternative resources.

Southeastern's Interaction with the Wholesale Market

Southeastern interacts with the wholesale electricity markets less than the other PMAs. Southeastern is a registered balancing authority in the SERC region but it does not own any transmission infrastructure. A majority of the SEPA footprint does not lie within an organized wholesale market (no RTO or ISO). Unlike the other three PMAs, it is not as concerned with defining its relationship with those organized markets. Changes in hydropower operations associated with increased penetration of variable renewables, which have been discussed for the other PMAs, have not been a significant issue for Southeastern. The Southeast is the region with the lowest penetration of renewables in the United States and none of the five states Southeastern sells most of the available federal hydropower to have a renewable portfolio standard in place.

⁵³ There are slight differences in the seasonality of generation between the GA-AL-SC and Cumberland systems. The percentage of total generation that takes place in the months of December through March is 36% in the GA-AL-SC system and 43% in the Cumberland system. As for summer (July through September) generation, it accounted in average for 24% of its annual generation in the GA-AL-SC system and only 19% in the Cumberland system.

The main interaction between Southeastern and other electricity market participants is for the purchase of replacement power and the sale of surplus power. Ideally, the PMA would prefer to purchase replacement power during periods in which the price of electricity in the region is low and sell surplus power when the price is high. Monthly data on replacement power purchases and surplus power sales are not available; thus dynamics between buying/selling of energy and price cannot be directly analyzed. An indirect approach for investigating this relationship is to conduct a correlation analysis between monthly generation at the USACE plants whose power is marketed by Southeastern and the regional price. Months in which generation is lowest are more likely to be the ones in which replacement power purchases occur and vice versa.

With no RTO that performs the centralized day-ahead dispatch and with limited transactions in trading platforms like the Intercontinental Exchange, electricity prices in the Southeast region are difficult to track. Bilateral contracts, for one year or more, account for most of the wholesale electricity transactions in the region. Trading for next day delivery is unusual except during periods of electric system stress (Whitmore, 2008). The system lambda for the two balancing authorities overlapping with the Cumberland and GA-AL-SC systems serves as a price proxy. System lambda is “the incremental cost of energy of the marginal unit assuming no system constraints”⁵⁴ and is commonly used as a proxy for the electricity price in those regions that do not have an independent system operator or RTO in its footprint. Balancing authorities report their system lambda for each hour of the year in FERC Form 714. Fig. 6.12 displays the generation output (TWh) and system lambdas (\$/MWh).

A correlation analysis was performed using available system lambda data from Southern Company and TVA control areas between 2006 and 2012. The correlation coefficients between Cumberland system generation and TVA Control Area lambda and between GA-AL-SC generation and Southern Company lambda were -0.277 and -0.252, respectively. A negative correlation is to be expected given that generation peaks in the winter, while demand—and prices —, peak in the summer. In addition, the year with the highest prices (2008) in this period coincided with low water levels in federal reservoirs in the Southeast. The low magnitude of the correlations can be explained by a combination of factors. First, the balancing authorities and states in which this part of the federal fleet is located are dominated by thermal plants and have low reliance on hydropower output. The percentage of in-state generation that came from hydropower on average in 2011-2013 was 12.7% in Tennessee, 6.4% in Alabama, 3.1% in Kentucky, 2.4% in Georgia, and 2.1% in South Carolina. Thus, months or years of low hydropower generation do not trigger large increases in the electricity prices observed in the region. Second, competing uses and operational rules set by USACE water control manuals strongly influence the timing of generation and have little to do with price signals.

⁵⁴ <http://www.ferc.gov/legal/staff-reports/2014/AD14-15-performance-metrics.pdf>

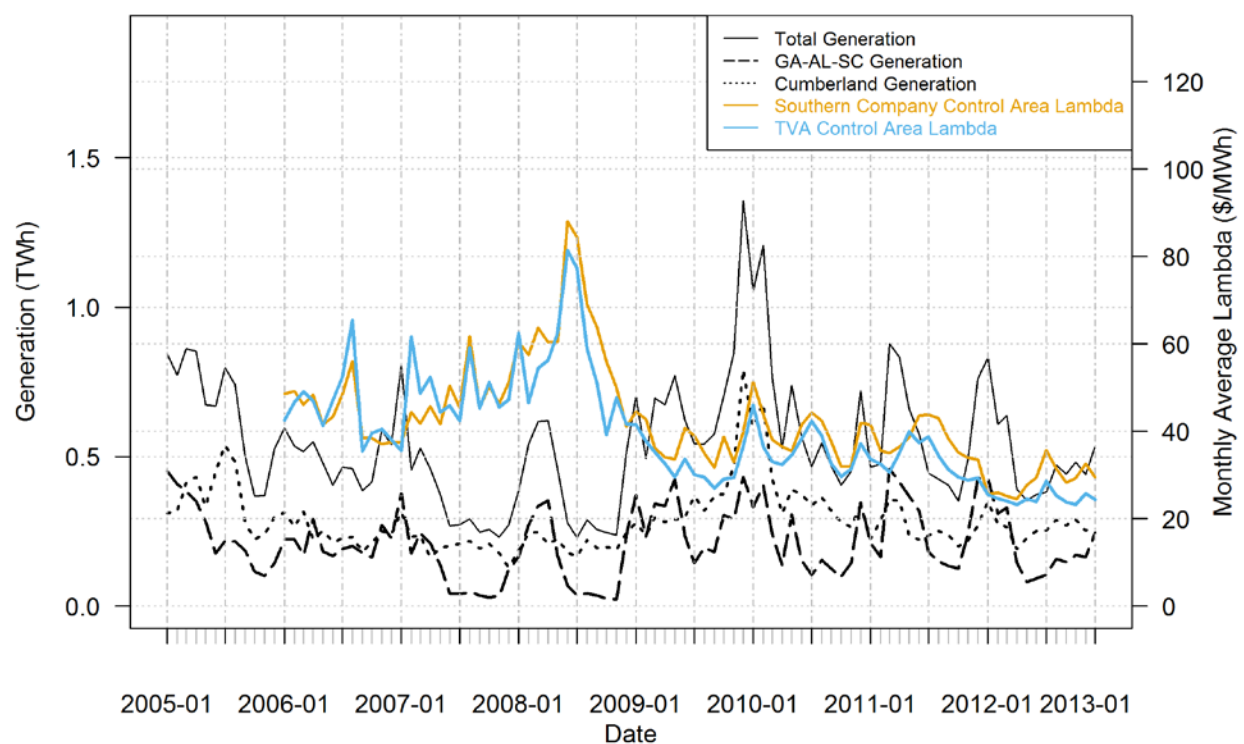


Fig. 6.12. Monthly hydropower generation marketed by Southeastern vs. monthly average system lambda for Southern Company and TVA Control areas

7 SUMMARY AND CONCLUSIONS

Hydropower is a key contributor to the US renewable energy portfolio for both its established development history and the diverse benefits it provides to electric power systems. Ensuring the sustainable operation of existing hydropower facilities is of great importance to the US renewable energy portfolio and the reliability electricity grid. The study provides a broad assessment that addresses how climate change may affect future US federal hydropower generation. A spatially consistent assessment approach (Section 2) is designed to evaluate 132 federal hydropower plants that are marketed by four PMAs. The results present a regional discussion regarding the effects and risks of future climate change to this hydropower fleet in Sections 3 to 6. Section 7 presents the interregional summary, major findings, conclusions, and future research.

7.1 Summary of Analysis and Findings

7.1.1 Interregional Summary

A series of hydroclimate models and analytical methods was used to gradually downscale the global climate change signals into watershed-scale hydrologic and hydropower projections to support climate change impact assessment. Among the ten selected climate models, the projected multimodel median changes in temperature, precipitation, runoff, and generation in each PMA study area for both near-term (2011–2030) and midterm (2031–2050) future periods are summarized in Table 7.1. In each cell of Table 7.1, the projected annual change is tabulated in the center, with upper-left corner showing winter (DJF; December-January-February), upper-right showing spring (MAM; March-April-May), lower-left showing summer (JJA; June-July-August), and lower-right showing fall (SON; September-October-November). For precipitation, runoff, and generation, a positive change is marked by blue while a negative change is marked by red. Percentage changes that are greater than +10% or less than -10% are high-lighted in bold. The main finding includes:

- Air temperature is projected to increase in all areas and in all seasons by about +2 °F in the near-term and +3.5 °F in the midterm future periods. Larger increases are projected in the Western and Bonneville regions.
- In terms of multimodel median, annual precipitation is projected to increase slightly. A large multimodel uncertainty and regional variability of precipitation projections were also identified. Overall, more precipitation is projected in the midterm than near-term future periods. A higher increase of precipitation is projected in the Southwestern and Southeastern regions, as well as in the WAPA-1 area in the Upper Missouri River Basin.
- The projection of future runoff varies significantly by regions. In the snowmelt-dominated regions (such as most of Bonneville and Western), the winter and spring runoff is projected to increase, while the summer and fall runoff is projected to decrease. Such shift of runoff seasonality is likely caused by the increasing air temperature and earlier snowmelt. In the rainfall-dominated regions (Southwestern, Southeastern, and some areas of Bonneville and Western), the change of runoff is mainly controlled by the change of precipitation. In terms of the range of change, the percentage change of future runoff is larger than the percentage

change of precipitation. The result is consistent with the findings from the hydrologic model sensitivity analysis presented in Section 2.4.4.

- The change of future hydropower generation is mainly controlled by the change of future runoff and precipitation. Since the combined reservoir storage may provide a buffer to help absorb part of the runoff variability, the projected change of future hydropower generation is found to be in a smaller magnitude than the projected change of future runoff (for example, WAPA-4 that covers Hoover Dam and Lake Mead). The impact of the reduction of runoff variability on hydropower generation is less noticeable in regions with larger reservoir storage capacity (such as Bonneville and Western). For regions with smaller storage capacity (such as Southwestern and Southeastern), the change of future hydropower generation will follow the change of future runoff more closely.

7.1.2 Climate Projections

To project future climate conditions at the horizon of several decades and beyond, a GCM remains the most scientifically defensible approach. However, given the current modeling and computational limitations, the raw GCM outputs are still at a coarser spatial resolution (~150km) that cannot be directly used for an impact assessment at regional and watershed scales. Following a similar approach to the first 9505 assessment (Sale et al. 2012), a regional climate model, RegCM4, was used to dynamically downscale the climate signals into a finer spatial resolution. Ten GCMs from the CMIP5 archive are selected to generate ten sets of historical (1966–2005) and future (2011–2050) realizations under the RCP 8.5 emission scenario. The downscaled climate projections (e.g., temperature, precipitation, and wind speed) are then used to support the hydrologic and hydropower simulation.

While most of the findings and discussion of this study are based on these ten selected GCMs, they are only one part of the larger set of CMIP5 global projections. Although there are over 50 GCMs that contributed to the CMIP5, less than one third of them archive three-dimensional atmospheric fields at the sub-daily timescale, which is necessary for dynamical downscaling. Therefore, the choice of CMIP5 GCMs in this study is mainly based on the availability of sub-daily three-dimensional atmospheric data rather than the performance of pre-downscaled GCMs. The performance of the pre-downscaled GCMs is not evaluated in this study.

It should also be noted that given the climate modeling uncertainty, the findings and results of this study could be different than other concurrent hydroclimate studies based on different climate models and/or downscaling techniques. In order to better understand the difference among these ten dynamically downscaled climate projections and other downscaled climate products, a model intercomparison effort is conducted jointly with Reclamation. A total of 97 statistically downscaled climate projections under four emission scenarios (RCP 2.6, 4.5, 6.0, and 8.5) were obtained from the BCSD data archive from Reclamation (Brekke et al. 2013). For each PMA study area and Reclamation's watershed, the projected changes of temperature and precipitation from baseline (1966–2005) to future (2011–2050) periods were summarized for comparison.

Table 7.1. Summary of multimodel median projection of temperature, precipitation, runoff, and generation from baseline (1966–2005) to near-term (2011–2030) and midterm (2031–2050) future periods for each PMA study area

Win Annual Sum	Spr Fall	Multimodel median change from baseline (1966–2005) to future (2011–2030 & 2031–2050) periods							
		Δ Temperature (°F)		Δ Precipitation (%)		Δ Runoff (%)		Δ Generation (%)	
		Near-term	Midterm	Near-term	Midterm	Near-term	Midterm	Near-term	Midterm
BPA-1		+1.8 +2.1	+2.9 +2.7	+1 +3	+11 +8	+10 +6	+25 +24	+2 +7	+11 +25
		+2.0	+3.4	0	+5	-6	+2	-6	+2
		+2.9 +1.6	+4.2 +3.4	+1 -1	+2 +5	-15 -8	-15 -4	-17 -11	-14 -10
BPA-2		+1.7 +2.4	+3.2 +3.6	+1 0	+8 +5	+12 +3	+18 +14	+6 +3	+13 +14
		+2.2	+3.8	+1	+4	-1	+4	-1	+4
		+2.4 +1.9	+4.3 +3.8	0 -5	+1 0	-13 -7	-7 -2	-13 -7	-8 -2
BPA-3		+1.9 +2.4	+3.2 +2.9	+1 0	+9 +9	+6 -6	+21 +9	0 +7	+8 +19
		+1.9	+3.4	0	+7	-7	+6	-5	+5
		+2.5 +1.6	+3.8 +3.5	0 -4	+1 +1	-17 -9	-13 -2	-13 -9	-9 -7
BPA-4		+1.4 +2.4	+2.4 +2.9	-1 -2	0 +4	+5 -10	+7 0	+3 -7	+5 +1
		+2.0	+3.4	-3	+1	-6	-1	-6	-2
		+2.6 +1.8	+3.9 +3.4	-2 -8	-7 0	-19 -7	-20 -1	-13 -8	-13 -3
WAPA-1		+1.7 +1.7	+3.1 +3.0	+6 +2	+13 +10	+10 +16	+13 +27	+3 +9	+9 +12
		+1.7	+3.3	+5	+6	+7	+12	+5	+11
		+2.4 +1.7	+3.8 +3.5	0 +5	0 +7	-4 +5	+1 +7	+2 +2	+10 +10
WAPA-2		+1.6 +1.8	+2.9 +3.8	+6 +3	+10 +2	+4 +26	+2 +33	-7 +19	-10 +27
		+2.1	+3.7	+3	+3	+3	+1	+3	+2
		+2.3 +1.9	+4.0 +3.6	+2 +1	0 +2	-8 -5	-14 -7	+5 -7	-3 -11
WAPA-3		+1.8 +2.1	+3.3 +4.6	+10 +1	+5 -2	+7 +23	+8 +28	+1 +17	-6 +22
		+2.2	+4.1	0	+2	+3	+2	+3	+2
		+2.3 +2.1	+3.9 +3.6	-1 +1	0 +4	-10 -4	-16 -5	+4 -4	+4 -7
WAPA-4		+2.2 +1.9	+3.5 +4.3	+8 -1	+5 -12	+32 +5	+13 -8	+8 +8	-1 +6
		+2.2	+4.0	+1	-4	+18	+4	+6	+3
		+2.3 +1.9	+3.9 +3.5	-3 +5	-3 +4	+13 +21	+2 +11	+6 +3	+4 +2
WAPA-5		+1.6 +0.6	+3.7 +4.2	-3 -1	-8 -4	+11 +14	+9 +3	+23 +14	+21 +18
		+0.9	+3.8	+2	+1	+19	+18	+10	+12
		+1.2 +0.5	+4.1 +4.0	-4 +3	+4 +1	+17 +30	+42 +25	+1 +7	+4 +6
WAPA-6		+1.5 +2.4	+3.2 +4.2	+6 -2	+7 0	-7 -12	+6 -4	-15 -10	+4 +2
		+2.0	+4.0	-2	+2	-13	-2	-12	0
		+2.4 +2.2	+4.4 +3.8	-5 -16	-10 0	-15 -18	-12 -4	-6 -17	-1 -6
SWPA-1		+1.9 +1.4	+3.3 +2.9	+5 +8	+4 +9	+3 +10	-1 +23	+4 +7	+1 +15
		+1.7	+3.0	+3	+7	+7	+17	+7	+13
		+1.8 +1.2	+2.6 +3.0	+9 -2	+6 +4	+15 +2	+25 +21	+15 +4	+21 +23
SWPA-2		+1.9 +1.4	+3.2 +3.4	+9 +6	-1 +7	+6 +16	-5 +29	+6 +8	+3 +10
		+1.9	+3.2	+5	+4	+15	+20	+12	+10
		+2.1 +1.5	+2.9 +3.1	+5 +4	+5 +3	+28 +9	+44 +18	+18 +7	+23 +14
SWPA-3		+2.2 +1.4	+3.0 +3.3	-3 +5	-9 +5	+5 +13	-1 +18	+7 +14	+5 +17
		+1.6	+3.0	+5	+7	+19	+26	+18	+20
		+2.1 +1.4	+2.9 +3.1	+4 +4	+15 -1	+23 +19	+40 +30	+18 +25	+23 +33
SWPA-4		+1.8 +1.4	+2.6 +2.7	-4 +11	0 +11	+3 +15	+18 +22	+12 +6	+13 +19
		+1.4	+2.7	+5	+6	+15	+22	+12	+16
		+1.7 +1.0	+2.7 +2.8	+9 -1	+11 +5	+17 +6	+29 +30	+13 +14	+14 +21

Table 7.1 (continued)

Win Annual Sum	Spr Fall	Multimodel median change from baseline (1966–2005) to future (2011–2030 & 2031–2050) periods							
		Δ Temperature (°F)		Δ Precipitation (%)		Δ Runoff (%)		Δ Generation (%)	
		Near-term	Midterm	Near-term	Midterm	Near-term	Midterm	Near-term	Midterm
SEPA-1		+1.8 +1.5	+2.9 +2.8	+6 +7	+8 -1	+8 +8	+8 -3	+8 +11	+6 -1
		+1.5	+3.0	+3	0	+6	-2	+6	-2
		+1.7 +1.0	+3.0 +2.8	+4 +6	-2 +3	+4 +8	-8 0	+4 +7	-7 0
SEPA-2		+1.9 +1.4	+2.9 +2.7	-4 +1	+2 +3	-3 +1	+4 +10	-3 0	+6 +5
		+1.5	+2.9	+1	+5	+1	+10	0	+7
		+1.6 +1.0	+2.6 +2.7	+4 -1	+2 +5	0 +6	+6 +8	-1 +3	+2 +9
SEPA-3		+1.6 +1.2	+2.4 +2.6	+1 +1	+4 +8	-1 +5	+4 +14	+1 +3	+5 +12
		+1.4	+2.8	+2	+5	+2	+10	+1	+7
		+1.7 +1.0	+3.1 +2.7	+3 +4	-2 +5	+5 +5	+3 +9	+2 +2	+4 +5
SEPA-4		+1.4 +1.2	+2.4 +2.6	+2 +5	+3 +4	+5 +12	+10 +11	+1 +1	+3 +2
		+1.3	+2.7	+4	+5	+10	+15	+2	+1
		+1.8 +0.9	+3.3 +2.7	+3 +1	-3 +7	+18 +11	+11 +13	+4 +2	+1 0

Note: In each cell, the projected annual change is tabulated in the center, with upper-left corner showing winter (DJF; December-January-February), upper-right showing spring (MAM; March-April-May), lower-left showing summer (JJA; June-July-August), and lower-right showing fall (SON; September-October-November). For precipitation, runoff, and generation, a positive change is marked by **blue**, while a negative change is marked by **red**. Percentage changes that are greater than +10% or less than -10% are highlighted in **bold**.

An example is shown in Fig. 7.1. The average percentage changes of precipitation and degree change of temperature from the 1966–2005 baseline to the 2011–2050 future period for the entire CONUS are calculated annually and for four seasons, including winter (DJF, December-January-February), spring (MAM, March-April-May), summer (JJA, June-July-August), and fall (SON, September-October-November). The ensemble median of 97 BCSD projections is marked by the dashed line in Fig. 7.1. All models projected a consistent increase in temperature ranging from 1 °F to 5 °F, and a -7% to +12% change in precipitation with relatively large inter-model variability across all seasons. While the ten dynamically downscaled climate models do not cover the full range of the BCSD projections, they spread around the median of BCSD, suggesting that the larger picture between these two downscaled climate projections should be consistent. It can also be seen that, although the highest emission scenario (RCP 8.5) is chosen in this study, the ten downscaled simulations are not biased toward the warming side. This is because the difference among various emission scenarios only becomes significant after 2030 (Peters et al. 2013). Hence, climate variability remains the main governing factor in the near-term future period. Similar figures are available for each PMA study area (Appendix C) to visualize the difference between these two downscaled data sets to support further future planning.

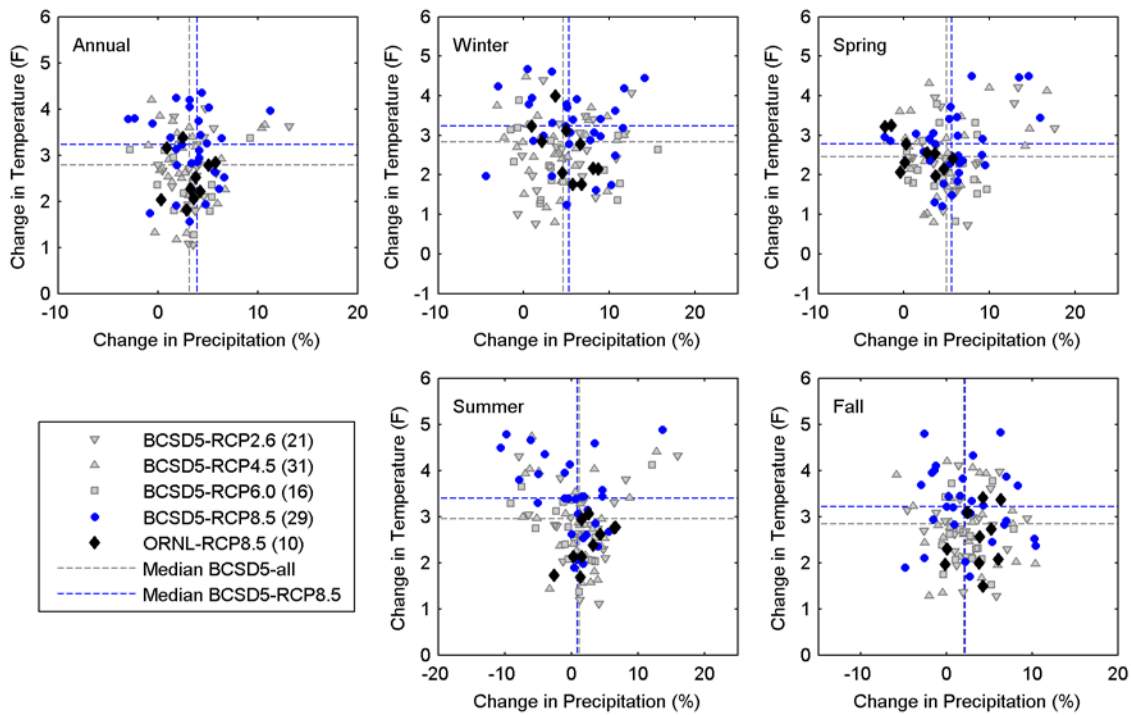


Fig. 7.1. Scatter plots of annual and seasonal temperature and precipitation changes for 97 statistically downscaled CMIP5 GCM projections under four emission scenarios (RCP 2.6, 4.5, 6.0, and 8.5; green symbols) plotted against the 10 RegCM4 simulations (blue symbols) selected for this study. The 97 climate projections were obtained from the BCSD data archive.

While different downscaling approaches, climate models, and emission scenarios were used in these two studies (and perhaps for all other concurrent hydroclimate studies), there is no implication of what method should be superior. Each model, method, and technique has its own strengths and limitations, so the selection of a particular method for climate projection should be driven by the user's specific needs. Taking statistical versus dynamical downscaling as an example, statistical downscaling can be efficiently applied to downscale temperature and precipitation for a large number of climate models so it can be used to study the full range of multimodel variability in future temperature and precipitation projections. On the other hand, while dynamical downscaling is fairly computationally intensive that can only be applied for limited models, it can downscale all climate variables (including atmospheric circulation, pressure, wind, precipitable water, etc.) simultaneously through a physical model. For hydrologic application, the main difference is how to generate daily and/or sub-daily storm inputs for hydrologic simulation. For dynamical downscaling, storms are directly simulated by a numerical model based on the projected future boundary conditions. As for statistical downscaling, the method typically applied is to first spatially disaggregate monthly precipitation (or temperature) into finer spatial resolution based on historic monthly observation. An analogue-type method is then used to sample and rescale similar storms from past observation to form daily or subdaily projections of future precipitation (e.g., Maurer et al. 2010). There are pros and cons in both approaches, so the decision again should be based on the research need.

From a water and energy manager's point of view, the focus on climate projection is not to deterministically debate which models and/or downscaling techniques could be more scientifically superior. Rather, from a probabilistic risk management perspective, it is more important to jointly evaluate a broad range of risks as suggested by different models and methods. The risks induced by climate change are among all other possible risks (e.g., equipment or infrastructure failure) that a resource manager needs to value and should not be ignored or over-emphasized. The climate projections generated by this study, along with other available climate research resources, could provide quantitative measures to support resource managers in making informed decisions.

7.1.3 Water Availability for Hydropower

To simulate the watershed response to the projected future meteorological conditions (i.e., temperature, precipitation, and wind speed), a calibrated hydrologic model is used in this study to simulate the future water availability for hydropower generation. Based on the VIC hydrologic model that was also used in the first 9505 assessment (Sale et al. 2012), additional efforts were invested to improve the spatial resolution, data quality, and model accuracy of hydrologic simulation. Using the downscaled daily temperature, precipitation, and wind speed as inputs, ten sets of hydrologic projections are simulated for the 1966–2005 baseline and the 2011–2050 future periods. The hydrologic model outputs were then used to evaluate the future climate change effects on watersheds upstream of all federal hydropower plants.

Spatial patterns in the projected runoff changes are summarized in Fig. 7.2 across all PMA areas. For near-term (2011–2030) and midterm (2031–2050) future periods, the percentage change of future annual runoff relative to the baseline (1966–2005) period was calculated at each grid point. The multimodel median and the 75th and 25th multimodel quantities are illustrated. In terms of the multimodel median, some spatial variability can be observed. In the near-term future period, the average annual runoff in the Pacific Northwest (BPA-1 to BPA-4), California (WAPA-6), and the Upper Rio Grande River Basin (northern WAPA-5) is projected to decrease, while in other PMA areas, the annual runoff is projected to increase. The midterm future period is in general wetter than near-term, but areas such as lower Colorado River (part of WAPA-4), Wyoming (WAPA-2) and eastern Texas (part of WAPA-5) are projected to be drier. Inherited from the high multimodel variability of precipitation projections, the multimodel variability of runoff is also high. The 75th and 25th quantile maps provide the information regarding the range of model uncertainty across the ten downscaled climate projections simulated in this study.

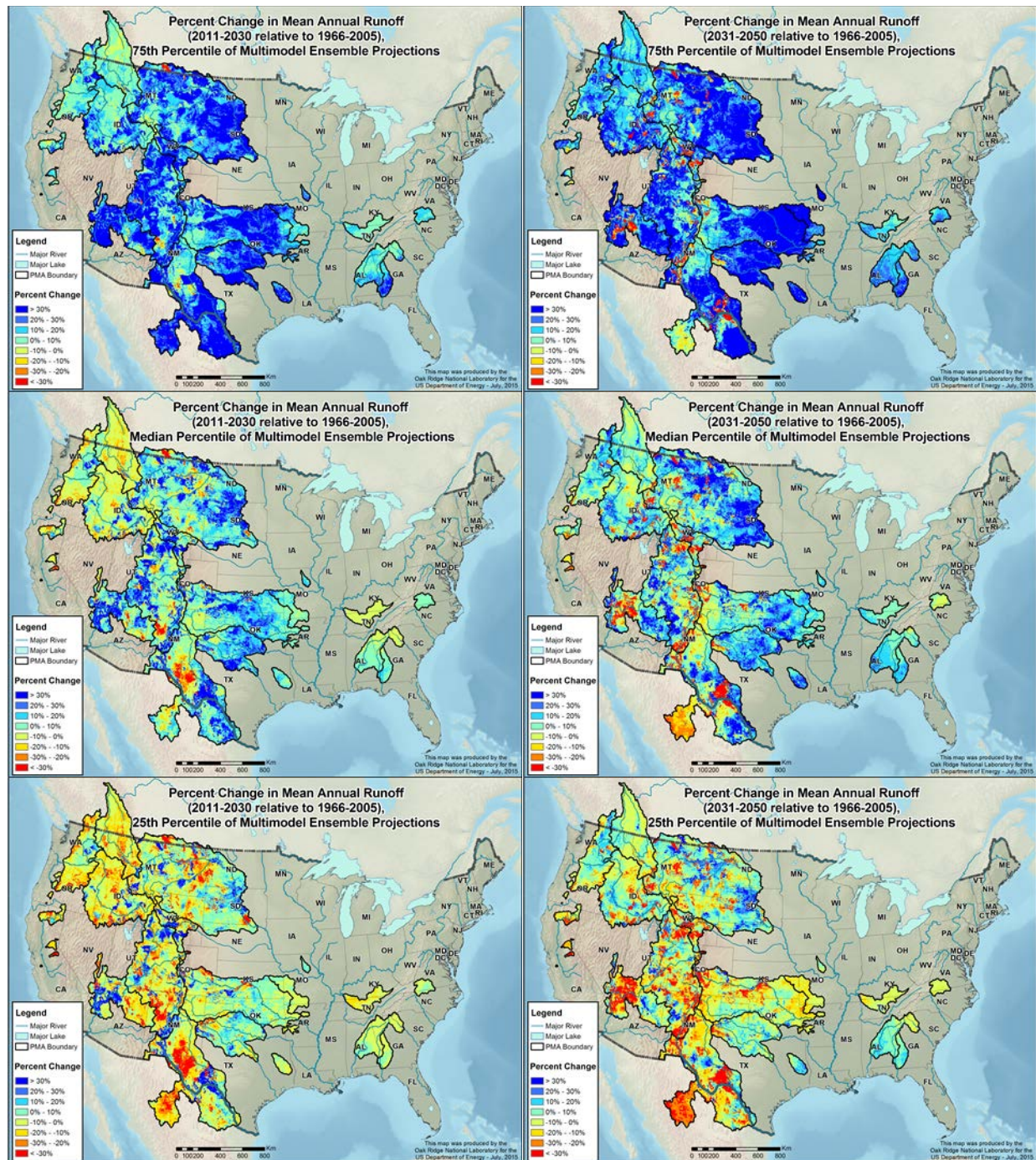


Fig. 7.2. Change in runoff projected for PMA regions over the near-term period (2011–2030, left) and the midterm period (2031–2050, right), based on the 25th, median (50th), and 75th multimodel ensemble quantiles.

It should be noted that while a labor and computationally intensive effort was used incorporated to improve the performance of VIC hydrologic model through intensive model calibration, the current model parametrization could still be further improved in many of the watersheds (discussed in Section 2.4). However, with a different model calibration method and objective function (e.g., calibrating mean or peak flow), the different model parameters may further alter the projections of future hydrologic conditions (e.g., Mendoza et al. 2015; Vano et al. 2014).

Such effect and sensitivity of model parameters on future hydrologic projections are yet to be extensively studied. Unlike the conventional water resource questions that usually focus on smaller scaled watersheds, one main challenge of a large-scale (e.g., CONUS) hydroclimate assessment is the availability of a consistently calibrated model for the entire study area. While there are various hydrologic models for different watersheds, VIC is one of the few models that has been implemented at the national and global scale. Nevertheless, as with multi-GCMs, each hydrologic model has its own assumptions, strengths, and limitations, so the use of multi-hydrologic models can potentially improve the projection of future hydrologic conditions. Moving forward, it is important to understand how different hydrologic modeling elements (e.g., ground water representation, dynamic land use change, and water demand) affect the results of future hydrologic projections and to determine the best strategy for hydrologic model selection and calibration to assess hydroclimate change impact. Further exploration of a broad range of hydroclimate modeling uncertainty will improve the resource managers' understanding of future hydrologic projections and their implications.

7.1.4 Federal Hydropower Generation

To simulate monthly and seasonal hydropower generation in the future climate condition, a lumped WRES model was designed for this study (Section 2.5). For each hydropower region, the WRES model used the monthly precipitation and naturalized (unregulated) runoff as inputs, performed a runoff mass balance calculation for the total monthly runoff storage in all reservoirs and retention facilities in the watershed, and simulated the monthly regulated runoff release and hydropower generation through the system. The WRES model was developed and calibrated using historic (1980–2009) monthly precipitation, runoff, and generation data. Overall, around 84% annual federal hydropower generation was satisfactorily simulated by WRES with the Nash-Sutcliffe coefficient greater than 0.7, and nearly 99% annual generation can be simulated with the Nash-Sutcliffe coefficient greater than 0.6. Driven by the downscaled hydroclimate projections, ten sets of monthly hydropower generation were simulated for the 1966–2005 baseline and 2011–2050 future periods to support impact assessment.

The total annual hydroelectric energy generated from each PMA region and from all PMA regions as a group is summarized in Fig. 7.3 for near-term and midterm future periods. To show the multimodel variability, each horizontal bar in Fig. 7.3 includes 10 smaller bars for each downscaled climate model, sorted descendingly from top to bottom. For comparison, the multimodel baseline (1966–2005) average is marked by the bold vertical black line. In terms of the annual generation from all PMA regions (i.e., 132 federal hydropower plants that are marketed through the four PMAs), the projected hydropower generation in the near-term future period is diverse, with half of the models suggesting increasing generation, and the other half suggesting decreasing generation. More hydropower generation is projected in the midterm future period, with 8 out of 10 models showing an increasing hydropower trend. Among all PMAs, the average near-term Bonneville hydropower generation is projected to decrease. The near-term change in the Western and Southeastern regions is diverse, with the multimodel median close to the baseline reference. In other regions and time periods, the annual hydropower generation is generally projected to increase. Such results are consistent with the projected change of total annual runoff in each PMA study area.

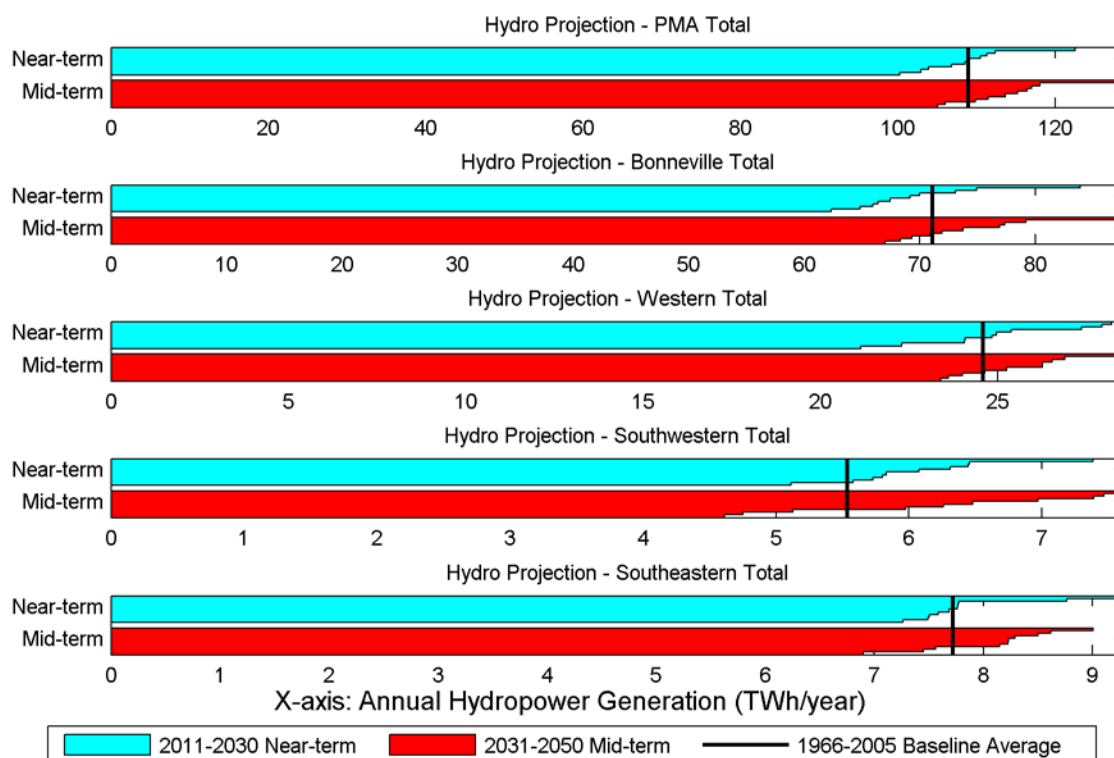


Fig. 7.3. Summary of annual hydropower projection in the near-term (2011–2030) and midterm (2031–2050) future periods for each PMA. Each horizontal bar consists of 10 smaller bars for each downscaled climate model (sorted descendingly from top to bottom). The multimodel baseline (1966–2005) average is marked in a bold black vertical line for comparison.

The seasonal hydropower projections are further summarized in Fig. 7.4. Following a similar setup to Fig. 7.3, the annual generation is broken down into four seasons, winter (DJF; December-January-February), spring (MAM; March-April-May), summer (JJA; June-July-August), and fall (SON; September-October-November). In terms of the total seasonal generation from all PMA regions, the majority of models project increasing generation in winter and spring, and decreasing generation in summer and fall. Such a result is mainly governed by the projected change in the Bonneville region, which is caused by the earlier snowmelt and changing runoff seasonality. A similar effect of earlier snowmelt on generation can also be observed in some Western study areas (Table 7.1), but it cannot be clearly seen in the Western total due to the diverse portfolio of hydropower plants across a wide range of geographical locations. Increasing seasonal generation is projected for both Southwestern and Southeastern, which is heavily controlled by the seasonal variability of precipitation and runoff. When compared to Bonneville and Western, the hydropower reservoirs in the Southwestern and the Southeastern have less storage capacity, so the projected change of seasonal hydropower generation will follow the projected change of seasonal runoff more closely.

It should be noted that the WRES model is developed and calibrated using the 1981–2012 hydropower, hydrology, and meteorology data, and hence it can only simulate how a current and stable hydropower system (i.e., without significant change of installed capacity) may react to the change of different meteorological and hydrologic inputs. This corresponds to one special feature of the US federal hydropower system: since the 1970s, there has been limited change of the total

installed capacity (Kao et al. 2015). This lack of change in the federal hydropower system resulted in rather stationary generation data that may enable development of a simplified hydropower model such as EBHOM (Madani and Lund 2009 and 2010) or WRES in this study. With WRES' model limitations in mind (Section 2.5.4), these findings are based on the assumption that there is no significant change in the future installed capacity and operation. The issues of aging infrastructures, competing water usage and indirect effects may reduce the system's ability to mitigate runoff variability and increase the difficulty of future operation. Moving forward, the resource managers may consider conducting more in-depth, site-specific studies using the reservoir-based models to explore how the adjustment of current operations may help reduce the increasing climate variability in the future.

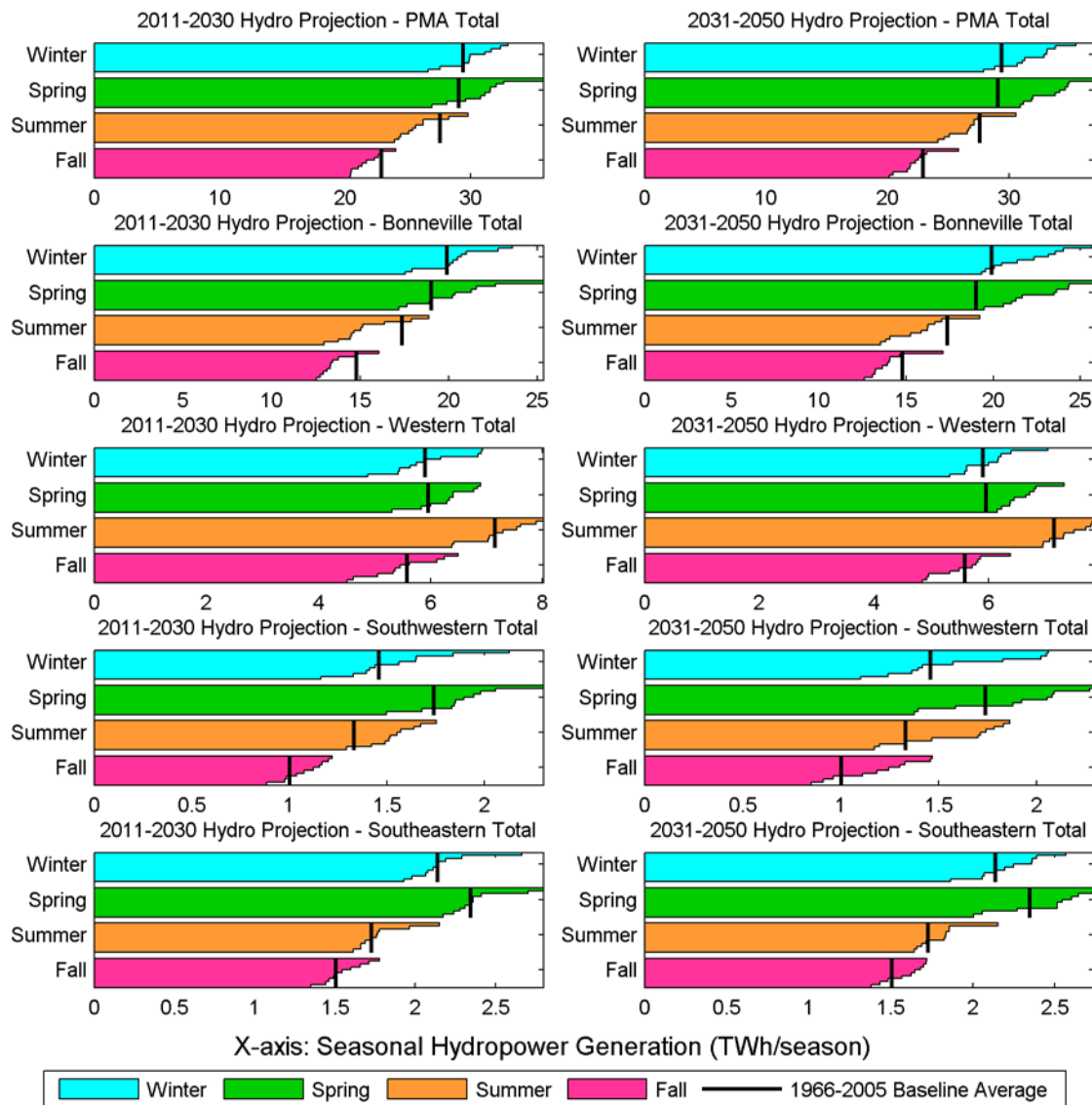


Fig. 7.4. Summary of seasonal hydropower projection in the near-term (2011–2030) and midterm (2031–2050) future periods for each PMA. Each horizontal bar consists of 10 smaller bars for each downscaled climate model (sorted descendingly from top to bottom). The multimodel baseline (1966–2005) average is marked in the bold line for comparison.

7.1.5 Power Marketing

PMAAs have substantial flexibility to accommodate hydrologic variability by adjusting the cost-based rates they charge to their customers. Rates are revised annually, and if needed, they are adjusted to ensure that power sales revenues will cover Treasury repayment obligations and the PMA's operation costs. Moreover, capacity and energy volumes allocated to customers in long-term contracts are based on conservative hydrological assumptions. As a result, replacement power purchases, whose cost is passed through to the customers, are a small fraction of total sales in most years. The existing flexibility levers should suffice for PMAAs to continue to fulfill their mission in the face of the climate variability and trends projected for the coming decades. Nonetheless, climate-driven changes in total annual generation, seasonality of generation, and frequency of extreme events (floods and droughts) might impact the competitiveness of federal hydropower versus alternative generation sources for the PMA customers.

The multimodel median projections, summarized in Table 7.1, indicate increases in generation in 27 out of the 36 study areas considered. The largest (double digit) projected generation increases correspond to Southwestern's marketing regions. Meanwhile, Bonneville is the PMA with the largest system-wide decreases in projected generation (but only in the near-term period). In marketing regions where total projected generation is substantially different from the historical trend, a question arises as to whether the PMAAs will modify the criteria used to determine how much capacity and energy to allocate among their customers in future long-term contract revisions. The criteria used until now vary across and within PMAAs, but they have generally been based on historical data.

Changes in the seasonality of generation might increase or decrease the value (i.e., avoided cost) that the federal hydropower marketed by PMAAs has for their customers. The direction of the change will depend on how strongly future generation patterns will correlate with customer load profiles, whose seasonality will be affected by the increased temperatures projected in all PMA regions. Warmer temperatures will increase summer peak load and decrease winter peak load, although the temperature effects may be offset through policies. The net effect on annual energy consumption is uncertain, and estimating it is of particular importance for Bonneville because of its statutory obligation to serve customers' load growth. In Southwestern and Southeastern, the cost avoided by the peaking power allocated to their customers (e.g., 1,200 hours in Southwestern's Integrated System, 1,500 hours in Southeastern's Cumberland System) will be highest in the summer months. Southwestern's projected increases in generation are larger in summer than in winter, which coincides with the peak season in their system. For Southeastern, the projected increase in summer peak load is not matched by a projected increase in summer generation.

PMA customers bear most of the financial risk associated with federal hydropower generation variability. However, PMAAs are letting customers decide whether they want to receive any energy—and pay the associated costs—beyond what is generated by the federal fleet. In Bonneville, customers can choose to procure their load growth or let the PMA do it. In some of Western's marketing regions, customers have the choice to handle their own replacement power purchases. Larger customers who own generation assets and participate more actively in the wholesale markets are more likely to prefer to arrange their own wholesale purchases and rely

less on the PMA. And that preference reveals that these customers expect to obtain more attractive prices and conditions than what they would get from the PMA.

Increased frequency of extreme runoff events leading to flood, or increased frequency of periods of drought, are projected consequences of climate change in the PMA regions. The projected increase in interannual variability underscores the importance of having contingency plans in place to manage both types of extreme events. Many of the federal projects whose power is marketed by the PMAs had flood control as one of their original authorized purposes and have well-developed rules to manage flood situations. The role of reservoirs in managing drought is equally important, but rules associated with drought management have not been as well established in all the river systems that contain federal hydropower. The 2007 guidelines for the operation of Lake Powell and Lake Mead during droughts and the 2015 Sustainable Water Management Plan published by the ACF Basin stakeholders exemplify the efforts being made to improve drought management protocols at multipurpose federal water reservoirs.

The challenges of the two PMAs (Bonneville and Western) that manage balancing authority areas are also evolving in ways that can indirectly affect their operations as federal power marketer, especially in those regions with significant penetration of variable renewables. As wind and solar generation capacity increases, particularly in hydro-dominated systems with little gas-fired generation, federal hydropower dispatch will not only depend on the set of operational rules and constraints set by USACE or Reclamation but also on wind and sun resource availability. Generation from non-dispatchable renewables can, during some peak hours, constitute an additional constraint for achieving the hydropower generation schedule that would be preferred by the PMA customers.

7.2 Future Assessment Needs

In this second 9505 assessment, an enhanced modeling framework is introduced to improve the simulation of future meteorological, hydrological, and hydropower conditions to support the evaluation of climate change effects on the US federal hydropower generation. While the improved modeling capabilities may help the water and energy resource managers examine the climate change induced risks more closely, there are further unresolved issues and research challenges that can be improved in the subsequent assessment. Some climate change and hydropower assessment needs include:

- **Data:** In order to evaluate the climate change effects on hydropower, a diverse set of data, including hydropower project characteristics, historic hydropower generation, observed hydrology and meteorology, and land surface information are needed. With the desire to continue improving the granularity of the assessment (e.g., from regional analysis to site-specific analysis), more detailed records, including reservoir characteristics, water usage information, river temperature measurement, operation rules, and marketing activities, will need to be comprehensively collected and organized into an integrated database to support national-scale assessment. Such objective will require the continual close collaboration among various water and energy resource agencies.
- **Modeling:** In addition to the continual learning of the most recent advancement on climate, hydrology, and water management, from a resource manager's point of view, it is also

important to better understand the broad range of uncertainty as suggested by different models and methods. Since each model, method, and technique has its own strengths and limitations, selection of a particular approach for hydroclimate simulation should be driven by the specific needs of the users. A comparative study on hydroclimate simulation, including GCM skills, downscaling techniques, hydrologic model selection, and data uncertainty, should be constantly conducted and tailored for the needs of water and energy resource managers. The existing downscaled hydroclimate data sets produced by various agencies may serve as a foundation for further exploration.

- **Power Marketing:** A quantitative estimation of the effects of temperature on seasonal peak loads and total energy consumption in each of the PMA marketing regions would provide valuable information to the agencies and their customers in their procurement and investment decisions. The statistical analysis would have to consider climate variables alongside other electricity demand drivers and take into account energy efficiency, demand response, and distributed generation projections. In addition, a closer look at the perspective of PMA customers and the strategies they are using to manage the financial risk associated with the variability in federal hydropower generation would bring additional useful insights to the discussion of power marketing.
- **Indirect Effects:** Except for the issues quantitatively analyzed in this second 9505 assessment, climate change can also affect competing water demands and environmental requirements that may indirectly constrain future hydropower operations (also known as indirect effects). For sustainable hydropower operation, such potential impacts should be further explored in the future assessment. This will rely on the close interaction among water and energy managers, climate and hydrologic scientists, and aquatic ecologists on translating the scientific findings into appropriate metrics to support decision making.
- **Collaboration:** The existing collaboration among various resource agencies, such as the interagency Climate Change and Water Working Group (www.ccawwg.us), may continue to provide an effective forum for resource planners to exchange the experience and perspectives regarding water management under a changing climate. The sharing of existing resources and expertise may help reduce the total amount of time and effort that each individual agency needs to invest. The collaboration may ultimately prompt the integrated climate change assessment with hydropower and other water resources planning activities so that the full spectrum of factors affecting water availability can be jointly considered. With the nexus between energy and water, how to effectively and sustainably utilize the limited natural resources remains one of the most challenging topics in the coming future.

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

- (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 MARKETING THROUGH POWER MARKETING ADMINISTRATIONS

N	Power plant name	Power system	Owner	Generation type	Capacity (MW)	1970–2012 average annual generation (GWh/year)
BPA-1 Upper Columbia						
1	Grand Coulee	Federal Columbia River Power System (FCRPS)	Reclamation	Conventional Hydro	6495	19,515.7
				Pumped Storage	314	
2	Hungry Horse		Reclamation	Conventional Hydro	428	924.8
3	Albeni Falls		USACE	Conventional Hydro	42	213.1
4	Libby		USACE	Conventional Hydro	525	1,772.9
BPA-2 Snake River						
5	Anderson Ranch	Federal Columbia River Power System (FCRPS)	Reclamation	Conventional Hydro	40	134.8
6	Black Canyon		Reclamation	Conventional Hydro	10.2	62.4
7	Boise R Diversion		Reclamation	Conventional Hydro	3.3	3.3
8	Minidoka		Reclamation	Conventional Hydro	27.7	101.1
9	Palisades		Reclamation	Conventional Hydro	176.4	637.8
10	Dworshak		USACE	Conventional Hydro	400	1,636.7
11	Ice Harbor		USACE	Conventional Hydro	603	2,132.1
12	Little Goose		USACE	Conventional Hydro	810	2,505.2
13	Lower Granite		USACE	Conventional Hydro	810	2,246.7
14	Lower Monumental		USACE	Conventional Hydro	810	2,536.8
BPA-3 Mid-Lower Columbia						
15	Chandler	Federal Columbia River Power System (FCRPS)	Reclamation	Conventional Hydro	12	49.6
16	Roza		Reclamation	Conventional Hydro	12.9	50.6
17	Bonneville		USACE	Conventional Hydro	1162	4,882.8
18	Chief Joseph		USACE	Conventional Hydro	2456.2	10,696.3
19	John Day		USACE	Conventional Hydro	2160	10,143.1
20	McNary		USACE	Conventional Hydro	990.5	6,201.7
21	The Dalles		USACE	Conventional Hydro	1819.7	7,489.0
BPA-4 Cascade Mountains						
22	Green Springs	Federal Columbia River Power System (FCRPS)	Reclamation	Conventional Hydro	17.2	65.2
23	Big Cliff		USACE	Conventional Hydro	18	92.4
24	Cougar		USACE	Conventional Hydro	26	134.8
25	Detroit		USACE	Conventional Hydro	100	374.7
26	Dexter		USACE	Conventional Hydro	15	74.0
27	Foster		USACE	Conventional Hydro	20	95.1
28	Green Peter		USACE	Conventional Hydro	80	242.4
29	Hills Creek		USACE	Conventional Hydro	30	158.6
30	Lookout Point		USACE	Conventional Hydro	120	330.2
31	Lost Creek		USACE	Conventional Hydro	49	226.1
WAPA-1 Upper Missouri						
32	Canyon Ferry	Pick-Sloan-Eastern Division	Reclamation	Conventional Hydro	49.8	378.2
33	Big Bend		USACE	Conventional Hydro	494.1	971.3
34	Fort Peck		USACE	Conventional Hydro	185.3	1,027.7
35	Fort Randall		USACE	Conventional Hydro	320	1,721.3

N	Power plant name	Power system	Owner	Generation type	Capacity (MW)	1970–2012 average annual generation (GWh/year)
36	Garrison		USACE	Conventional Hydro	614	2,221.7
37	Gavins Point		USACE	Conventional Hydro	132.3	713.7
38	Oahe		USACE	Conventional Hydro	784	2,614.5
39	Yellowtail ^a	Pick-Sloan-Eastern Division / Loveland	Reclamation	Conventional Hydro	250	851.1
WAPA-2 Loveland Projects						
40	Alcova	Loveland Area Projects (LAPs)	Reclamation	Conventional Hydro	41.4	119.5
41	Boysen		Reclamation	Conventional Hydro	15	69.8
42	Buffalo Bill		Reclamation	Conventional Hydro	18	65.6
43	Shoshone		Reclamation	Conventional Hydro	3	20.1
44	Heart Mountain		Reclamation	Conventional Hydro	5	24.7
45	Spirit Mountain		Reclamation	Conventional Hydro	4.5	14.4
46	Flatiron		Reclamation	Conventional Hydro	90	227.2
				Pumped Storage	8.5	
47	Big Thompson		Reclamation	Conventional Hydro	4.5	11.1
48	Fremont Canyon		Reclamation	Conventional Hydro	66.8	240.1
49	Glendo		Reclamation	Conventional Hydro	38	84.1
50	Green Mountain		Reclamation	Conventional Hydro	26	54.4
51	Guernsey		Reclamation	Conventional Hydro	6.4	20.0
52	Kortes		Reclamation	Conventional Hydro	36	146.1
53	Marys Lake		Reclamation	Conventional Hydro	8.1	38.0
54	Estes		Reclamation	Conventional Hydro	45	101.3
55	Mount Elbert		Reclamation	Pumped Storage	200	
56	Pole Hill		Reclamation	Conventional Hydro	38.2	177.5
57	Seminole	Reclamation	Conventional Hydro	51.6	138.8	
WAPA-3 Upper Colorado						
58	Blue Mesa	Salt Lake City	Reclamation	Conventional Hydro	86.4	266.7
59	Crystal		Reclamation	Conventional Hydro	28	168.4
60	Elephant Butte		Reclamation	Conventional Hydro	27.9	80.0
61	Flaming Gorge		Reclamation	Conventional Hydro	151.8	489.9
62	Fontenelle		Reclamation	Conventional Hydro	10	52.6
63	Glen Canyon Dam		Reclamation	Conventional Hydro	1312	4,546.3
64	Upper Molina		Reclamation	Conventional Hydro	9.9	30.7
65	Lower Molina		Reclamation	Conventional Hydro	5.6	17.8
66	McPhee		Reclamation	Conventional Hydro	1.2	3.5
67	Towaoc		Reclamation	Conventional Hydro	11.4	14.1
68	Morrow Point		Reclamation	Conventional Hydro	173.2	339.4
69	Deer Creek	Provo River	Reclamation	Conventional Hydro	4.8	25.1
WAPA-4 Lower Colorado						
70	Hoover Dam	Boulder Canyon	Reclamation	Conventional Hydro	2078.8	4,477.9
71	Davis Dam	Parker-Davis	Reclamation	Conventional Hydro	254.8	1,166.2
72	Parker Dam		Reclamation	Conventional Hydro	120	510.7

N	Power plant name	Power system	Owner	Generation type	Capacity (MW)	1970–2012 average annual generation (GWh/year)
WAPA-5 Rio Grande						
73	Amistad Dam & Power	Falcon-Amistad	IBWC	Conventional Hydro	66	137.3
74	Falcon Dam & Power		IBWC	Conventional Hydro	31.5	81.8
WAPA-6 California						
75	Folsom	Central Valley	Reclamation	Conventional Hydro	198.6	598.3
76	Judge F Carr		Reclamation	Conventional Hydro	154.4	468.3
77	Keswick		Reclamation	Conventional Hydro	117	444.7
78	New Melones		Reclamation	Conventional Hydro	300	447.9
79	Nimbus		Reclamation	Conventional Hydro	13.4	62.2
80	ONeill		Reclamation	Pumped Storage	25.2	
81	W R Gianelli		Reclamation	Pumped Storage	424	
82	Shasta		Reclamation	Conventional Hydro	714	1,930.0
83	Spring Creek		Reclamation	Conventional Hydro	180	569.5
84	Trinity		Reclamation	Conventional Hydro	140	468.5
85	Lewiston		Reclamation	Conventional Hydro	0.35	2.4
86	Stampede	Washoe	Reclamation	Conventional Hydro	3.6	10.1
SWPA-1 Upper White, Osage and Salt						
87	Beaver	Southwestern financially integrated projects	USACE	Conventional Hydro	112	154.6
88	Bull Shoals		USACE	Conventional Hydro	340	778.5
89	Clarence Cannon		USACE	Conventional Hydro	27	100.7
				Pumped Storage ^b	31	
90	Greers Ferry		USACE	Conventional Hydro	96	193.6
91	Harry S Truman		USACE	Pumped Storage ^c	161.4	260.9
92	Norfork		USACE	Conventional Hydro	80.4	200.1
93	Stockton		USACE	Conventional Hydro	45.2	53.1
94	Table Rock		USACE	Conventional Hydro	200	527.5
SWPA-2 Arkansas						
95	Dardanelle	Southwestern financially integrated projects	USACE	Conventional Hydro	160.8	631.5
96	Eufaula		USACE	Conventional Hydro	90	269.8
97	Fort Gibson		USACE	Conventional Hydro	44.8	222.0
98	Keystone		USACE	Conventional Hydro	70	272.8
99	Ozark		USACE	Conventional Hydro	100	279.4
100	Robert S Kerr		USACE	Conventional Hydro	110	576.8
101	Tenkiller Ferry		USACE	Conventional Hydro	39	123.5
102	Webbers Falls		USACE	Conventional Hydro	60	214.3
103	Broken Bow		USACE	Conventional Hydro	100	155.7
SWPA-3 Ouachita, Red and Brazos						
104	Blakely Mountain	Southwestern financially integrated projects	USACE	Conventional Hydro	75	178.9
105	DeGray		USACE	Conventional Hydro	40	83.6
				Pumped Storage (Reversible)	28	
106	Denison		USACE	Conventional Hydro	70	246.5
107	Narrows		USACE	Conventional Hydro	25.5	38.1
108	Whitney		USACE	Conventional Hydro	30	52.6

N	Power plant name	Power system	Owner	Generation type	Capacity (MW)	1970–2012 average annual generation (GWh/year)
SWPA-4 Neches						
109	Robert D Willis	Southwestern isolated projects	USACE	Conventional Hydro	8	27.9
110	Sam Rayburn		USACE	Conventional Hydro	52	116.8
SEPA-1 Kerr-Philpot						
111	John H Kerr	Kerr-Philpot	USACE	Conventional Hydro	196.8	445.1
112	Philpott Lake		USACE	Conventional Hydro	14	25.9
SEPA-2 Cumberland						
113	Barkley	Cumberland	USACE	Conventional Hydro	130	671.0
114	Center Hill		USACE	Conventional Hydro	135	364.0
115	Cheatham		USACE	Conventional Hydro	36	160.3
116	Cordell Hull		USACE	Conventional Hydro	99.9	366.8
117	Dale Hollow		USACE	Conventional Hydro	54	121.7
118	J P Priest		USACE	Conventional Hydro	28	70.3
119	Laurel		USACE	Conventional Hydro	70	64.4
120	Old Hickory		USACE	Conventional Hydro	103.7	478.3
121	Wolf Creek		USACE	Conventional Hydro	270	915.0
SEPA-3 GA-AL-SC						
122	Allatoona	GA-AL-SC	USACE	Conventional Hydro	86.6	145.1
123	Buford		USACE	Conventional Hydro	131.2	172.2
124	Carters		USACE	Conventional Hydro	250	461.3
				Pumped Storage	250	
125	Hartwell Lake		USACE	Conventional Hydro	420	442.7
126	J Strom Thurmond		USACE	Conventional Hydro	361.9	656.3
127	Millers Ferry		USACE	Conventional Hydro	101.1	351.4
128	Jones Bluff		USACE	Conventional Hydro	82	312.2
129	Richard B Russell		USACE	Conventional Hydro	300	680.8
				Pumped Storage	328	
130	Walter F George		USACE	Conventional Hydro	130	407.5
131	West Point		USACE	Conventional Hydro	73.3	184.7
SEPA-4 Jim Woodruff						
132	J Woodruff	Jim Woodruff	USACE	Conventional Hydro	43	211.8

^a Two of the four Yellowtail units are marketed as a Pick-Sloan-Eastern Division resource and two are marketed as a LAPs 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. COMPARISON OF HYDROCLIMATE PROJECTIONS WITH OTHER COMMONLY USED DATA SET

As discussed, given the different choice of GCMs, emission scenarios, and downscaling approaches, the downscaled climate projection data sets developed by various concurrent research efforts can be different. While these downscaled products are all scientifically plausible outcomes of future hydro-climate conditions, the different projections can result in planning challenges for water and energy resource managers. Before a best practice of hydro-climate model selection, downscaling, and bias-correction can be developed, one interim solution is to comprehensively examine and reveal the differences among different projection data sets. The comparative information can then help the resource managers get a broader view of model uncertainties and provide explanations for the differences among different studies.

To examine if the ten dynamically downscaled and bias-corrected climate projections (namely the ORNL projections in this section) have a reasonable representation among all other CMIP5 members, an examination is shown in Figure C1–C4. For comparison, 97 statistically downscaled climate projections under four emission scenarios (RCP 2.6, 4.5, 6.0, and 8.5) are obtained from the CMIP5-BCSD data archive (BCSD5; Brekke et al. 2013). The average percentage changes of precipitation and degree change of temperature from the 1966–2005 baseline to the 2011–2050 future period for the entire CONUS are calculated annually and for four seasons, including winter (DJF, December-January-February), spring (MAM, March-April-May), summer (JJA, June-July-August), and fall (SON, September-October-November). The ensemble median across all emission scenarios (BCSD5-all) and RCP 8.5 only (BCSD5-RCP8.5) are marked by dashed lines in Figure C1–C4. Since BCSD5 has been used in Reclamation’s SWA 9503 report, the difference shown in this appendix can help illustrate the somewhat different projections used by the two SWA studies.

In general, while the ten dynamically downscaled climate models do not cover the full range of the BCSD5 projections, they spread around the medians of BCSD5, suggesting that the larger picture between these two downscaled climate projections should be consistent. It can also be seen that, although the highest emission scenario (RCP 8.5) is chosen in this study, the ten downscaled simulations are not biased toward the warming side. This is consistent with our understanding that the difference among various emission scenarios only becomes significant after 2030 (Peters et al. 2013). For the near-term future, climate variability remains the main governing factor in the near-term future period. Some regional differences include:

- 1) In the Bonneville region, all models projected a consistent increase in mean annual temperature ranging from 1 °F to ~ 5 °F and -7% to ~ +12% change in precipitation with relatively large inter-model variability; the ORNL projections lie within a similar range (Figure C1). On seasonal basis, many models in this assessment show more decreases in winter and spring precipitation and less warming, while more extreme runoff events are projected in summer by the ORNL projections relative to BCSD5 particularly for BPA-1 through BPA-3. For BPA-4, the ORNL models are more scattered around the medians of BCSD in all seasons, but still not bias towards any direction.
- 2) In the Western region, most ORNL projections show similar variations in annual and seasonal changes in precipitation vs. temperature when compared to BCSD. However, for

spring, the ORNL simulation projected relatively drier and colder conditions particularly in WAPA-1 and WAPA-2 areas than most of the BCSD models (Figure C2).

- 3) When comparing to all BCSD projections, ORNL projections in the Southwestern region show similar variations in projected precipitation and temperature. However, most of the ORNL simulations projected relatively larger increase in annual and summer precipitation and show relatively less warming in temperature than BCSD projections (Figure C3).
- 4) In the Southeastern region, the ten ORNL projections are mostly spread around the median of BCSD and do not show noticeable bias towards any direction (Figure C4).

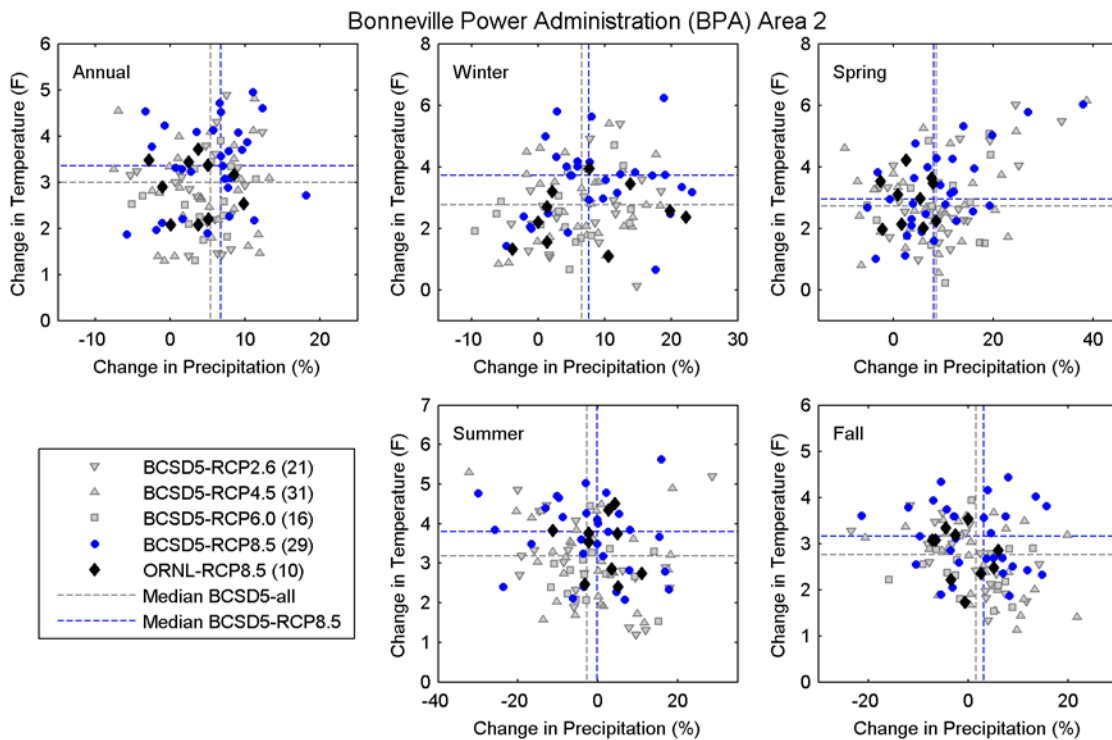
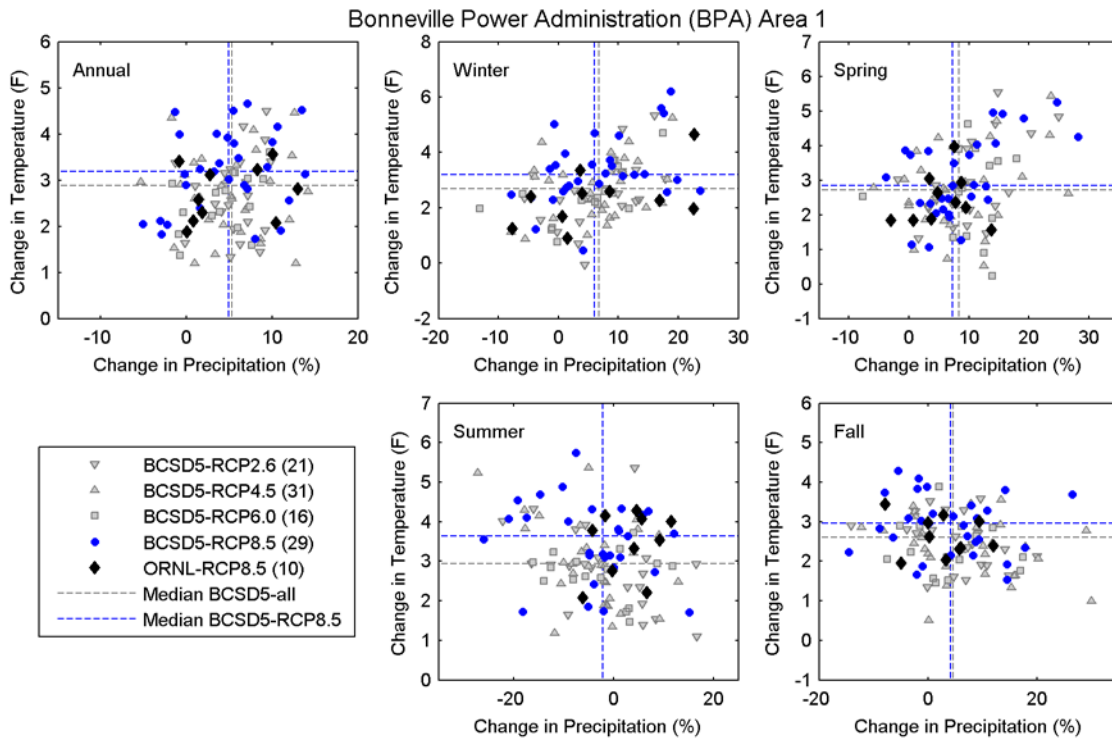


Figure C1. Comparison of the projected temperature and precipitation changes in the Bonneville region between ORNL and BCSD projections.

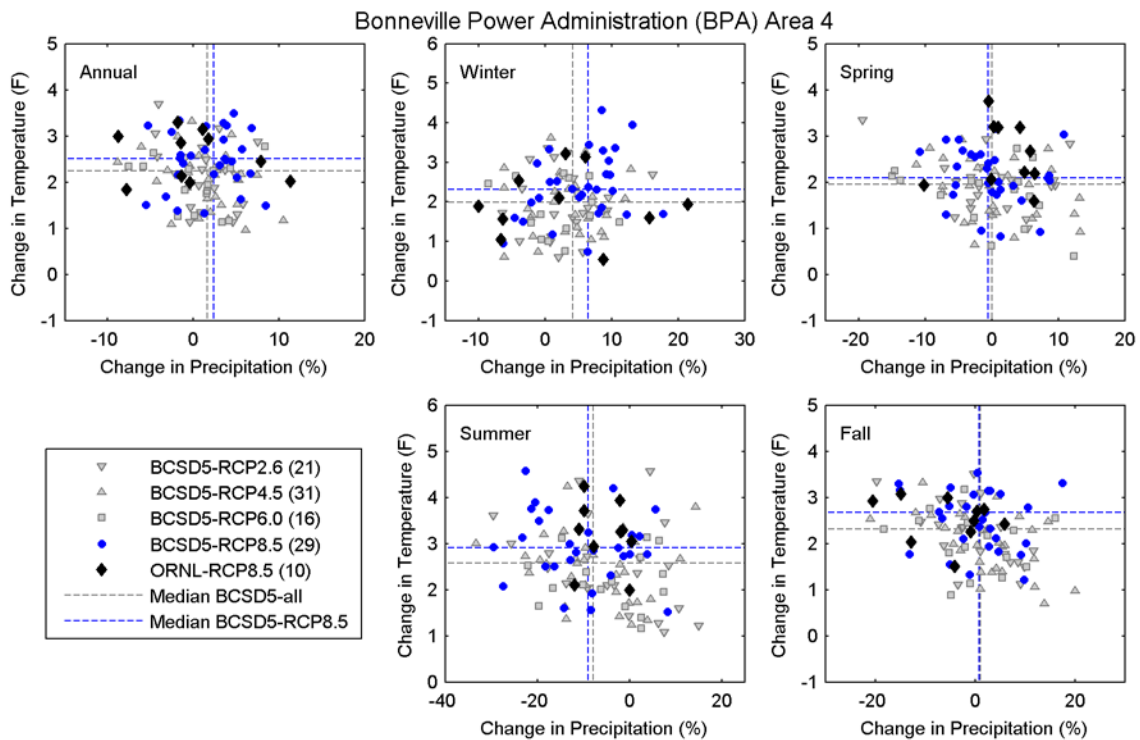
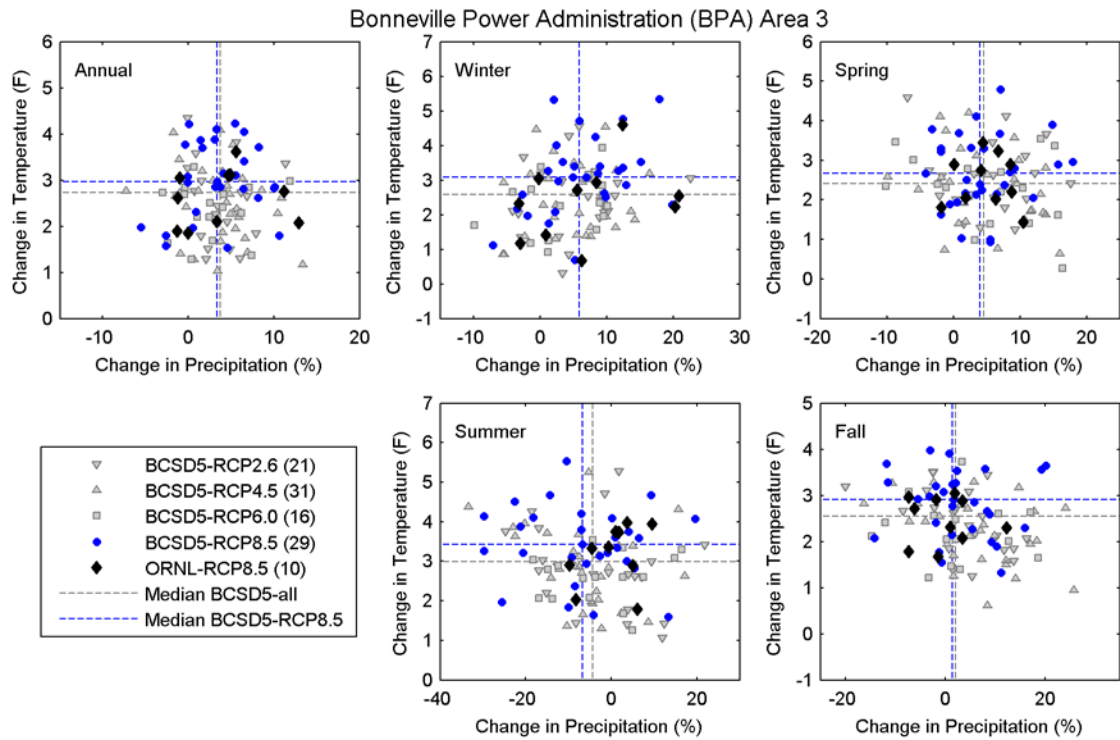


Figure C1 Comparison of the projected temperature and precipitation changes in the Bonneville region between ORNL and BCSD projections (cont).

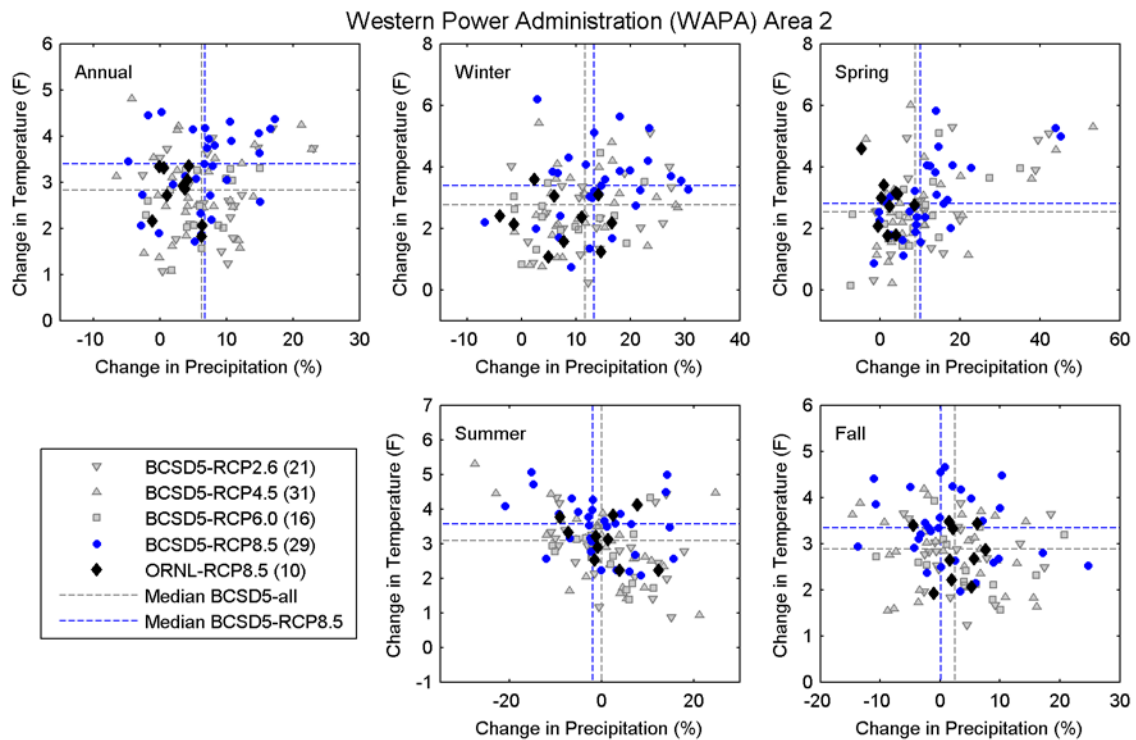
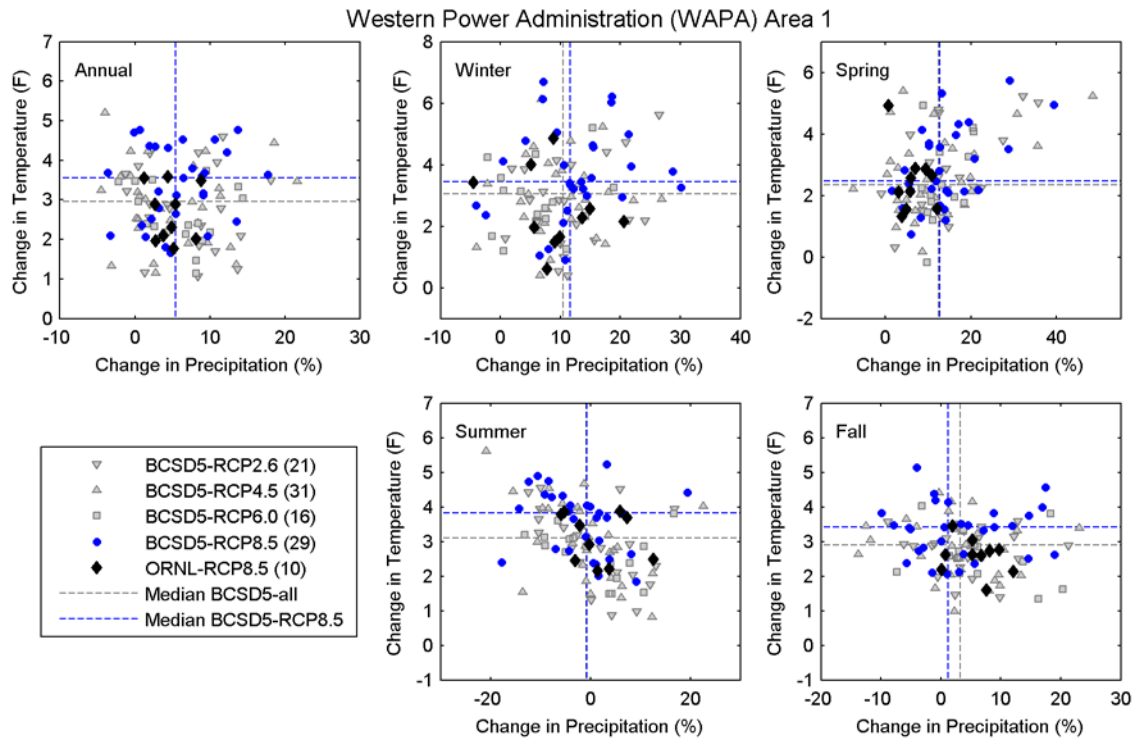


Figure C2 Comparison of the projected temperature and precipitation changes in the Western region between ORNL and BCSD projections.

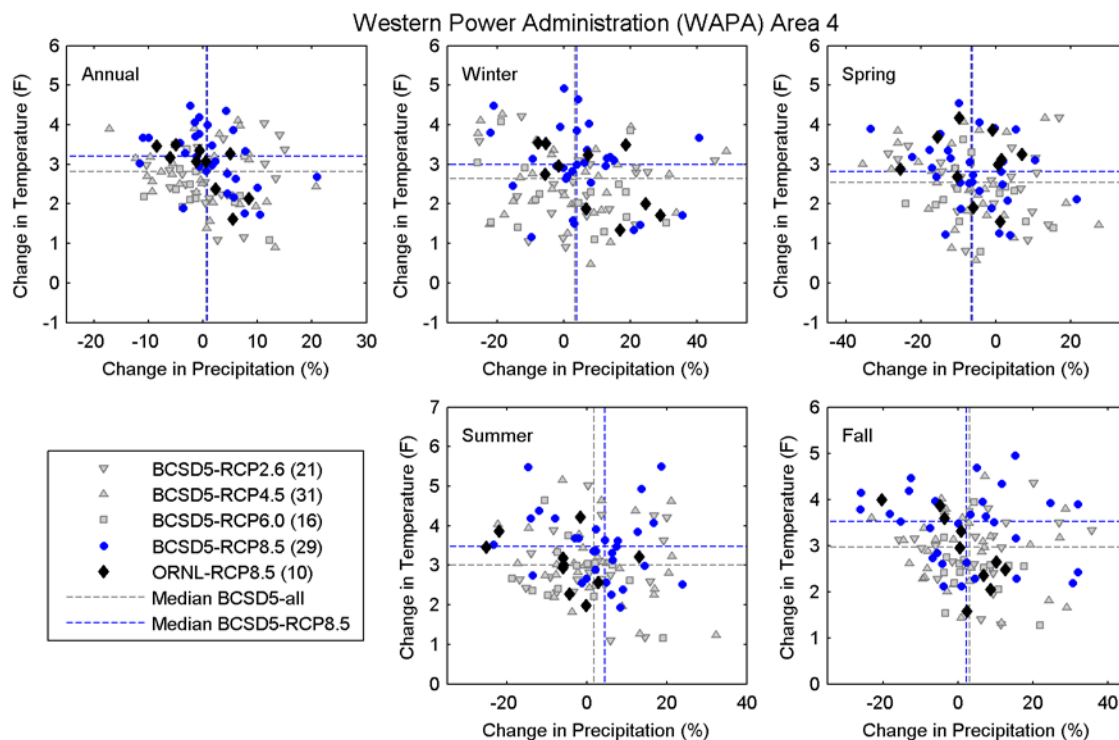
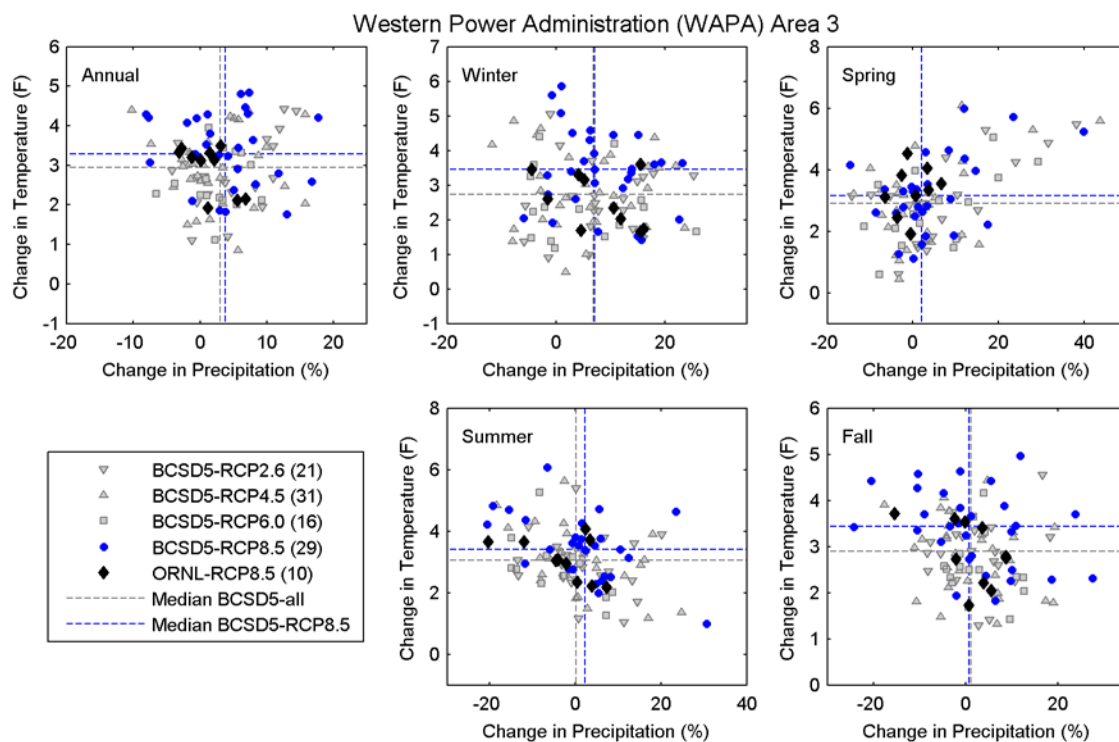


Figure C2 Comparison of the projected temperature and precipitation changes in the Western region between ORNL and BCSD projections (cont).

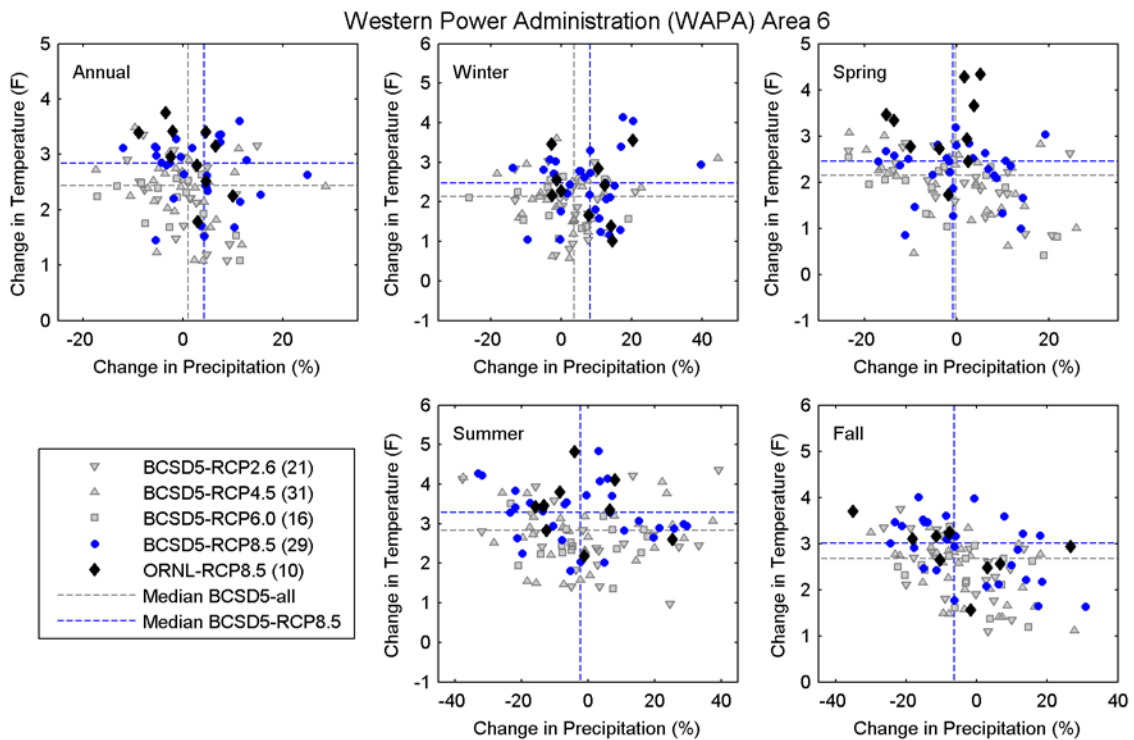
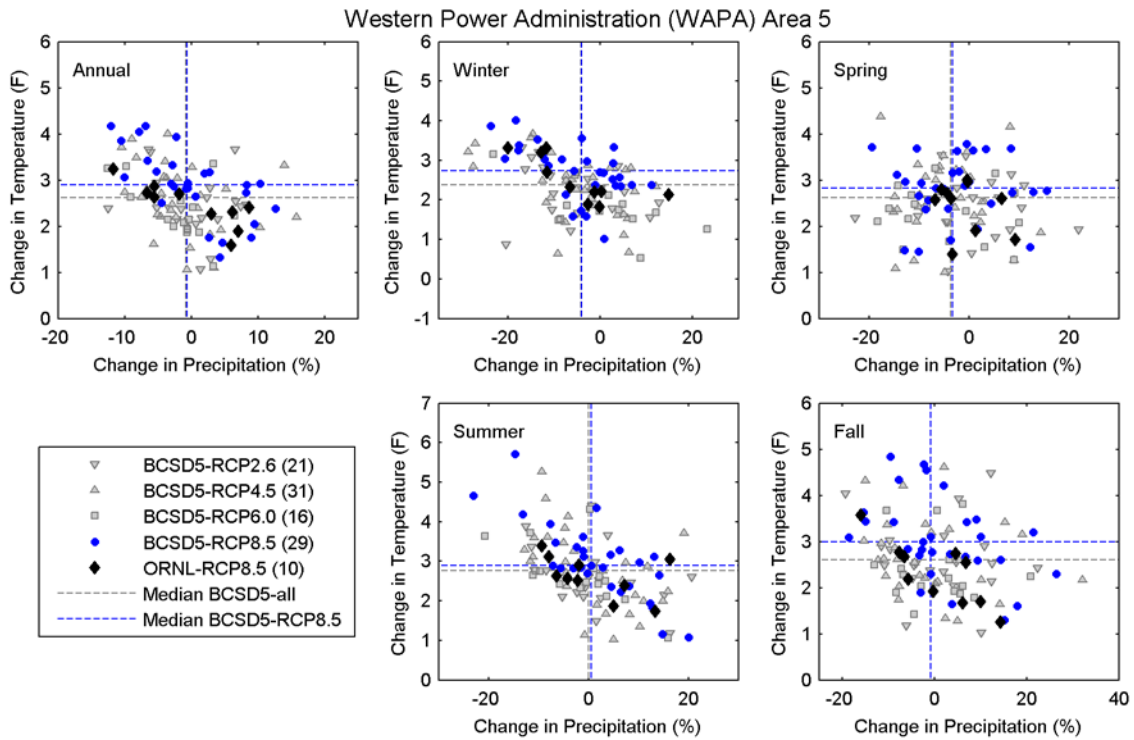


Figure C2 Comparison of the projected temperature and precipitation changes in the Western region between ORNL and BCSD projections (cont)

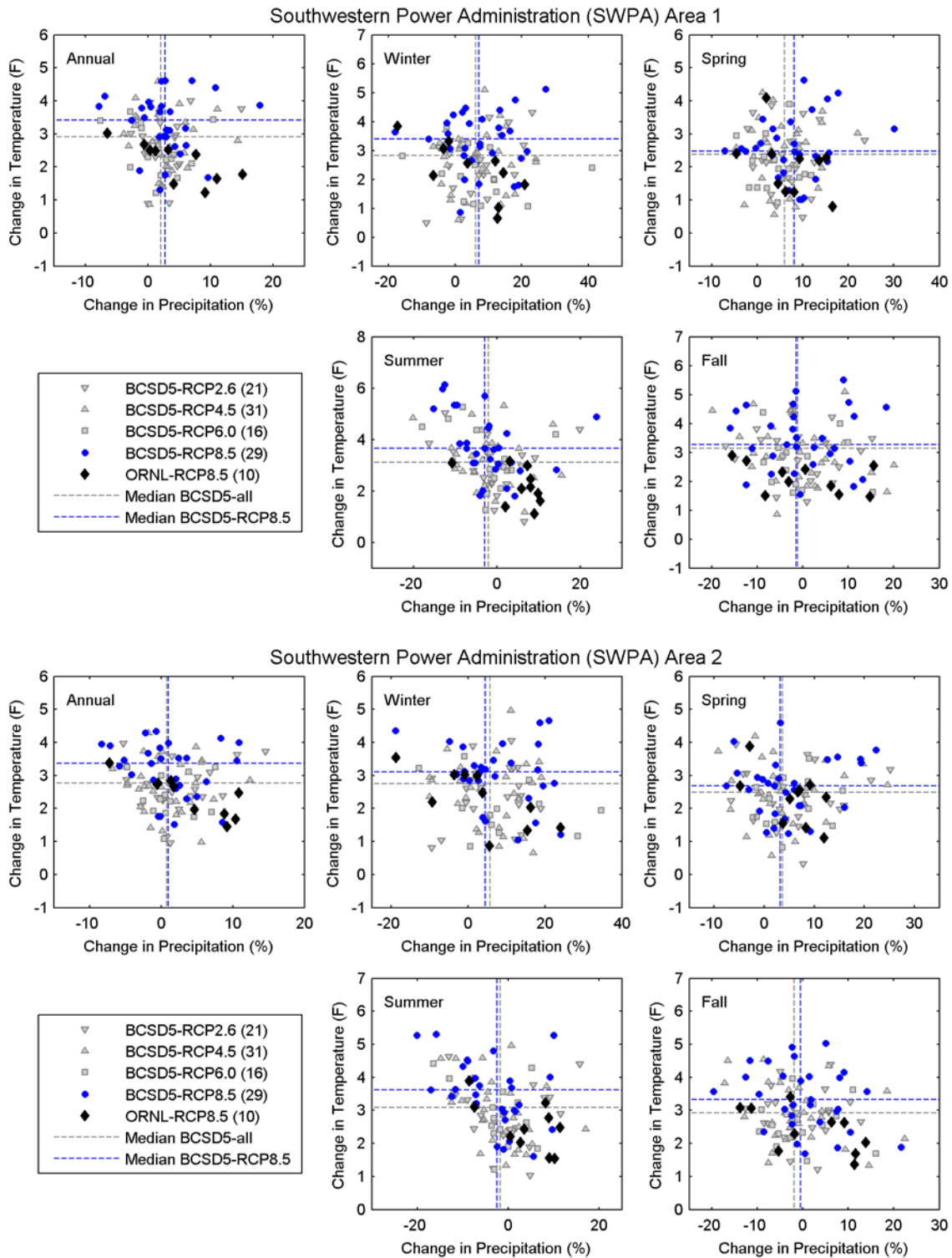


Figure C3. Comparison of the projected temperature and precipitation changes in the Southwestern region between ORNL and BCSD projections.

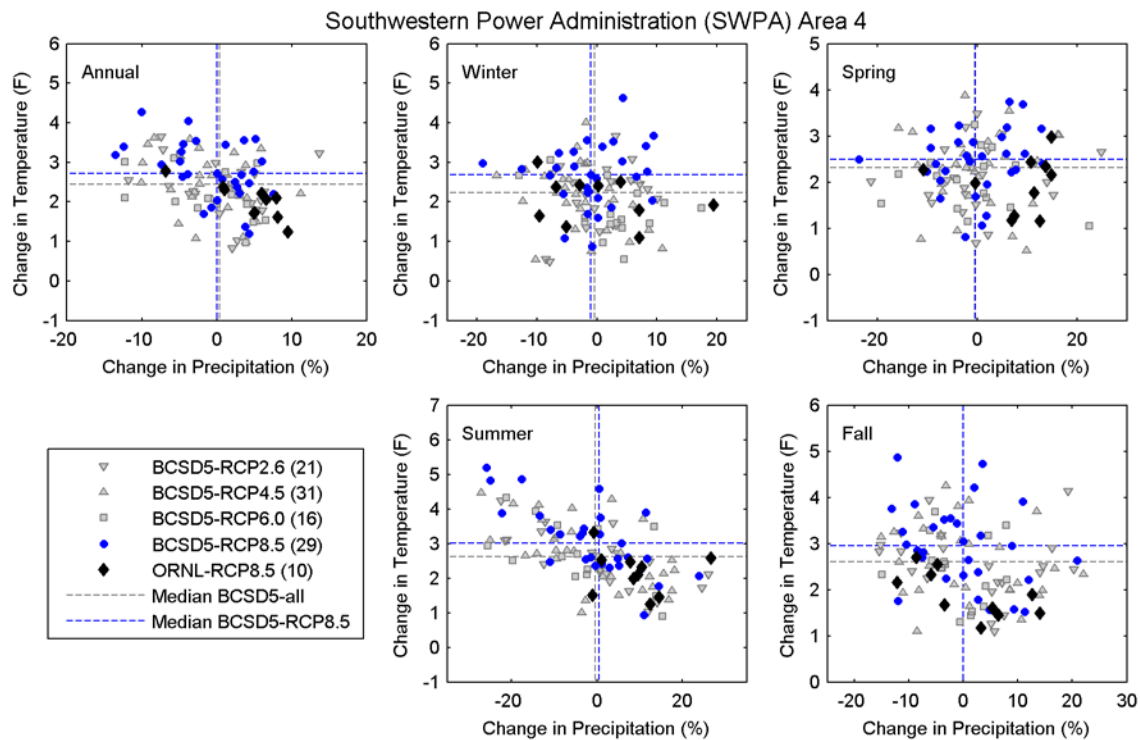
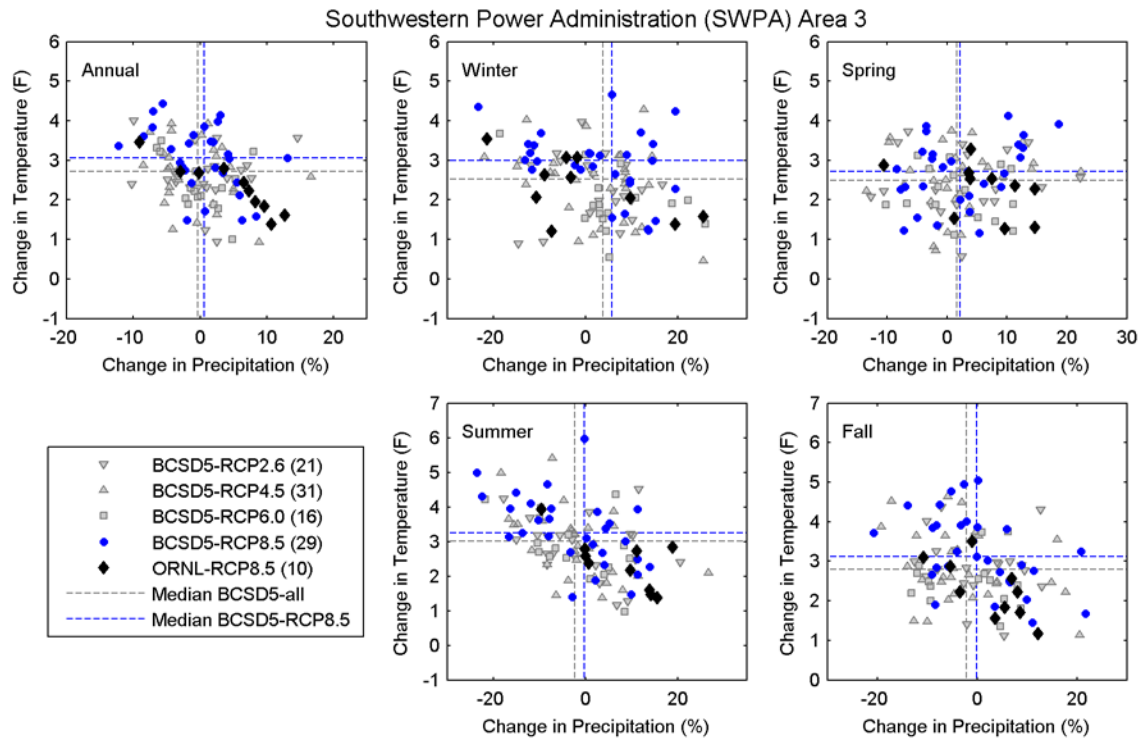


Figure C3 Comparison of the projected temperature and precipitation changes in the Southwestern region between ORNL and BCSD projections (cont).

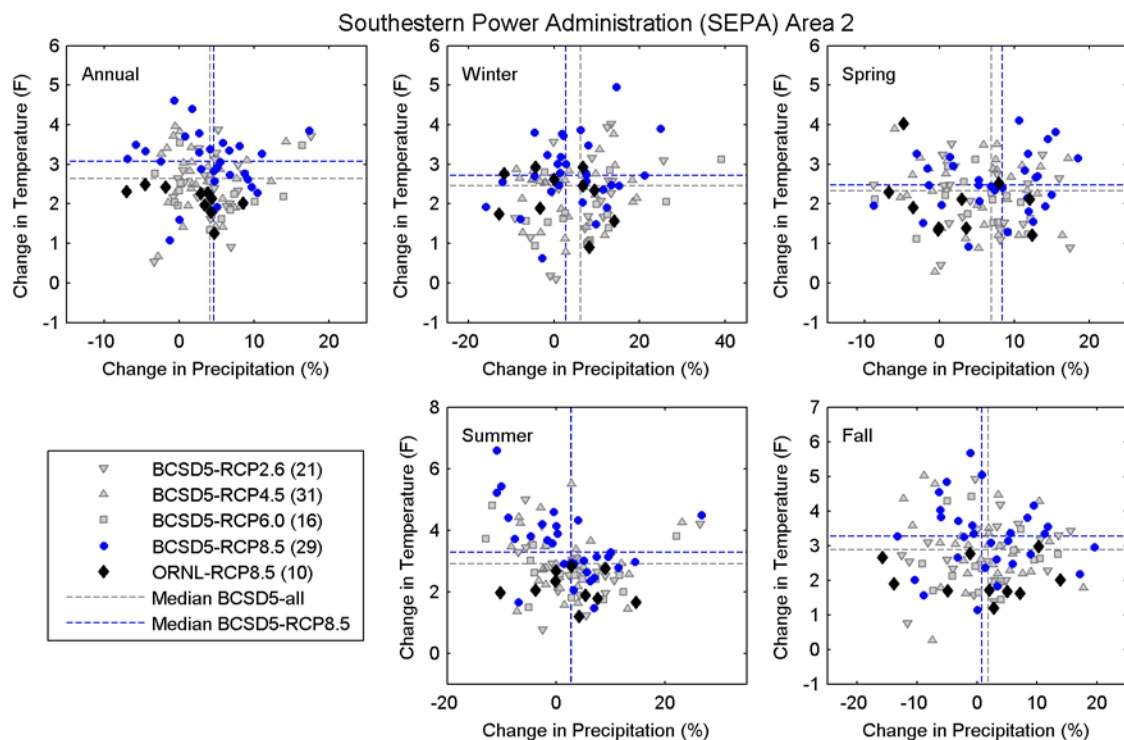
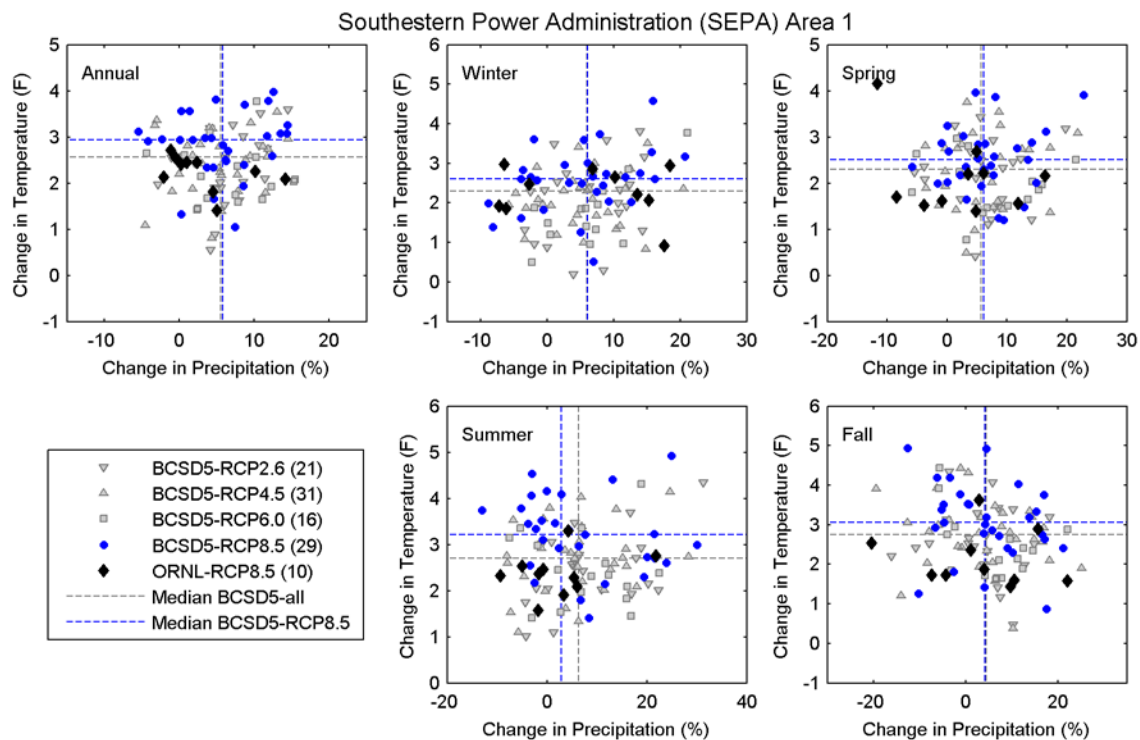


Figure C4. Comparison of the projected temperature and precipitation changes in the Southeastern region between ORNL and BCSD projections.

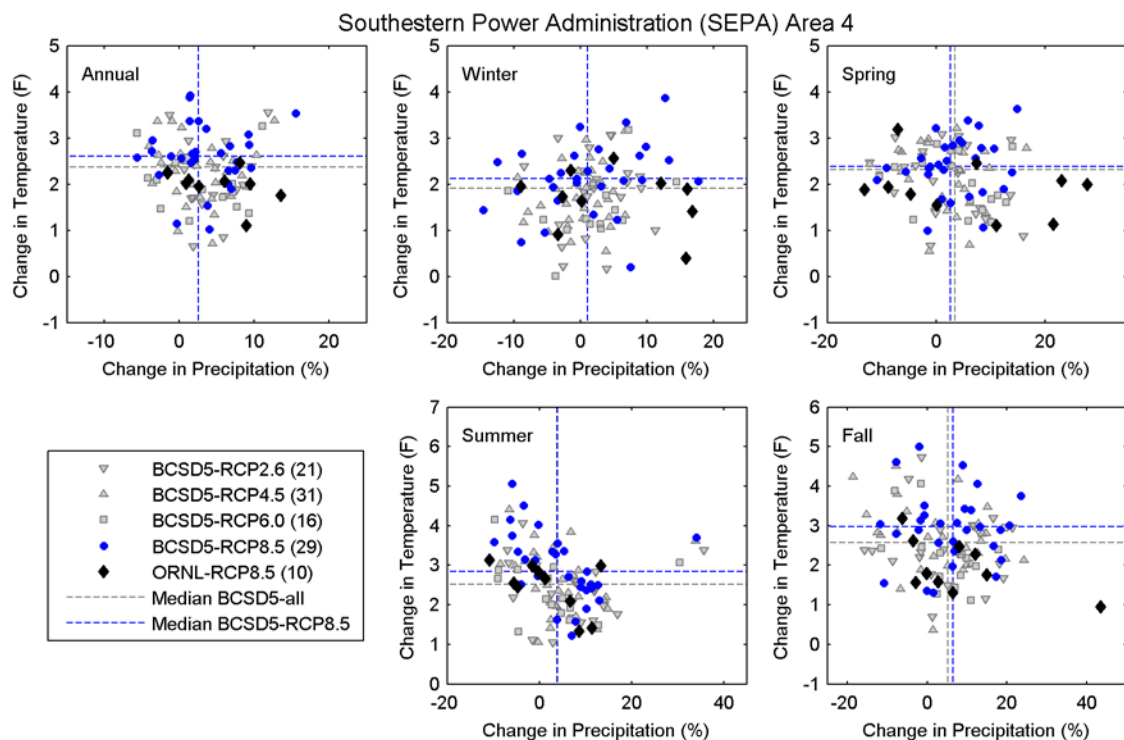
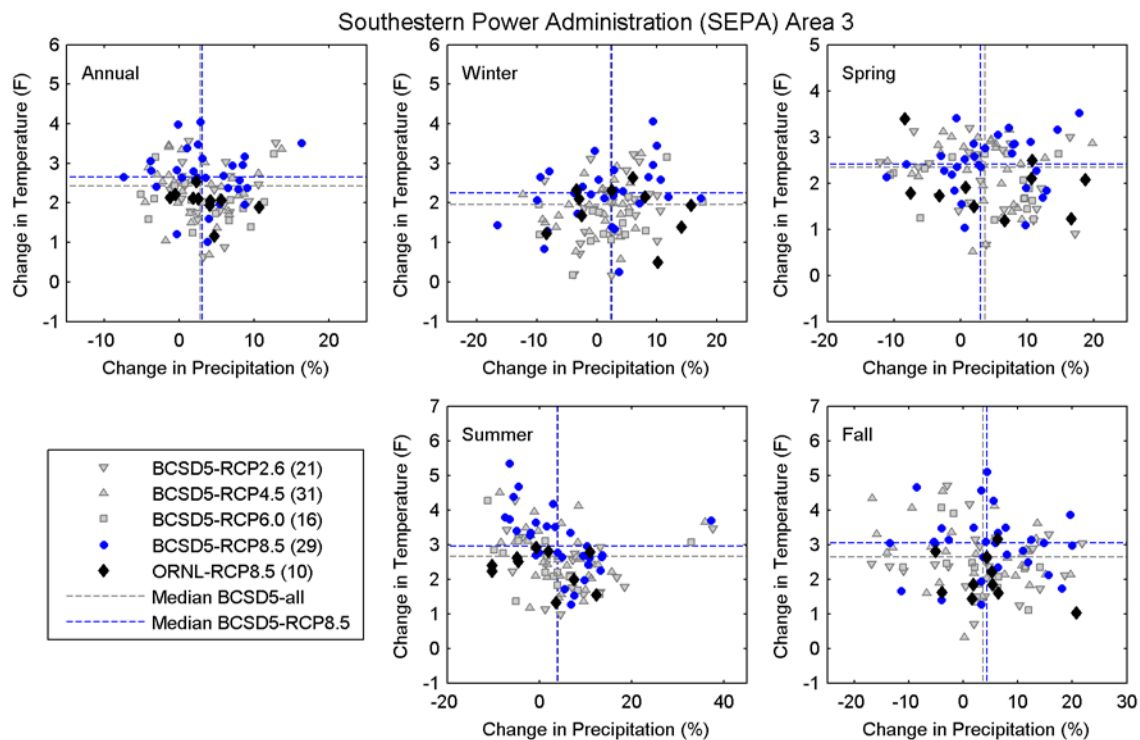
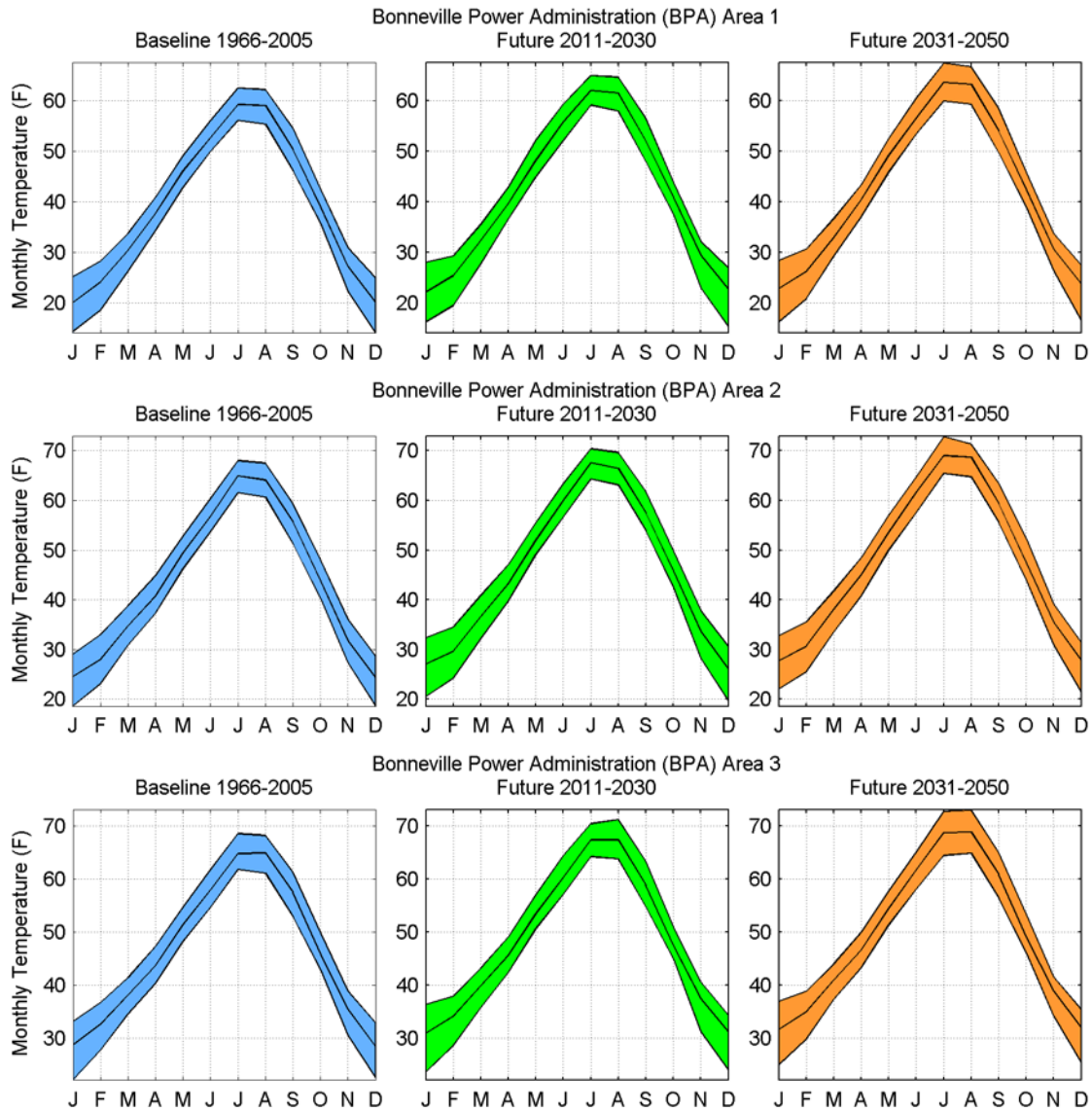


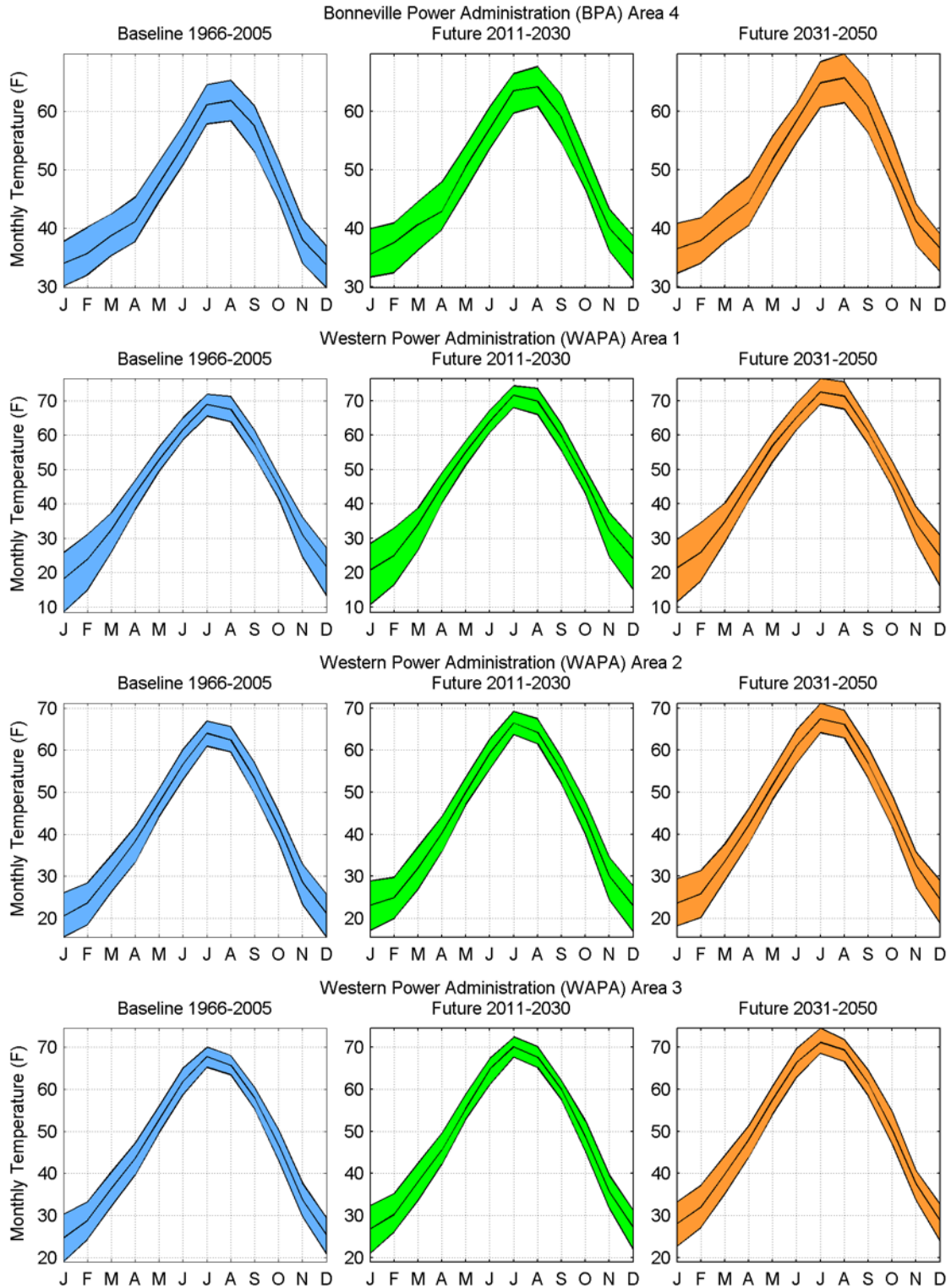
Figure C4 Comparison of the projected temperature and precipitation changes in the Southeastern region between ORNL and BCSD projections (cont).

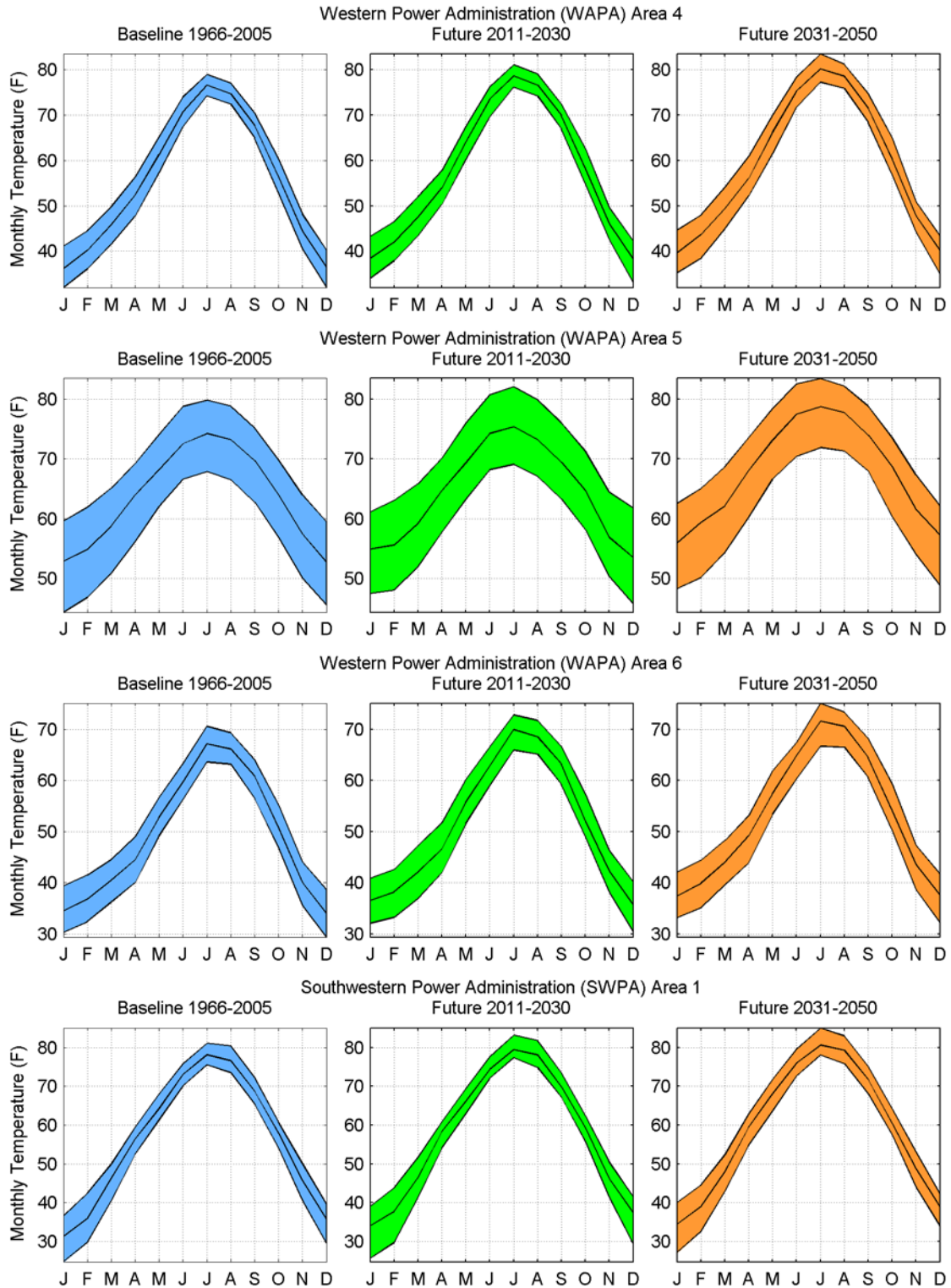
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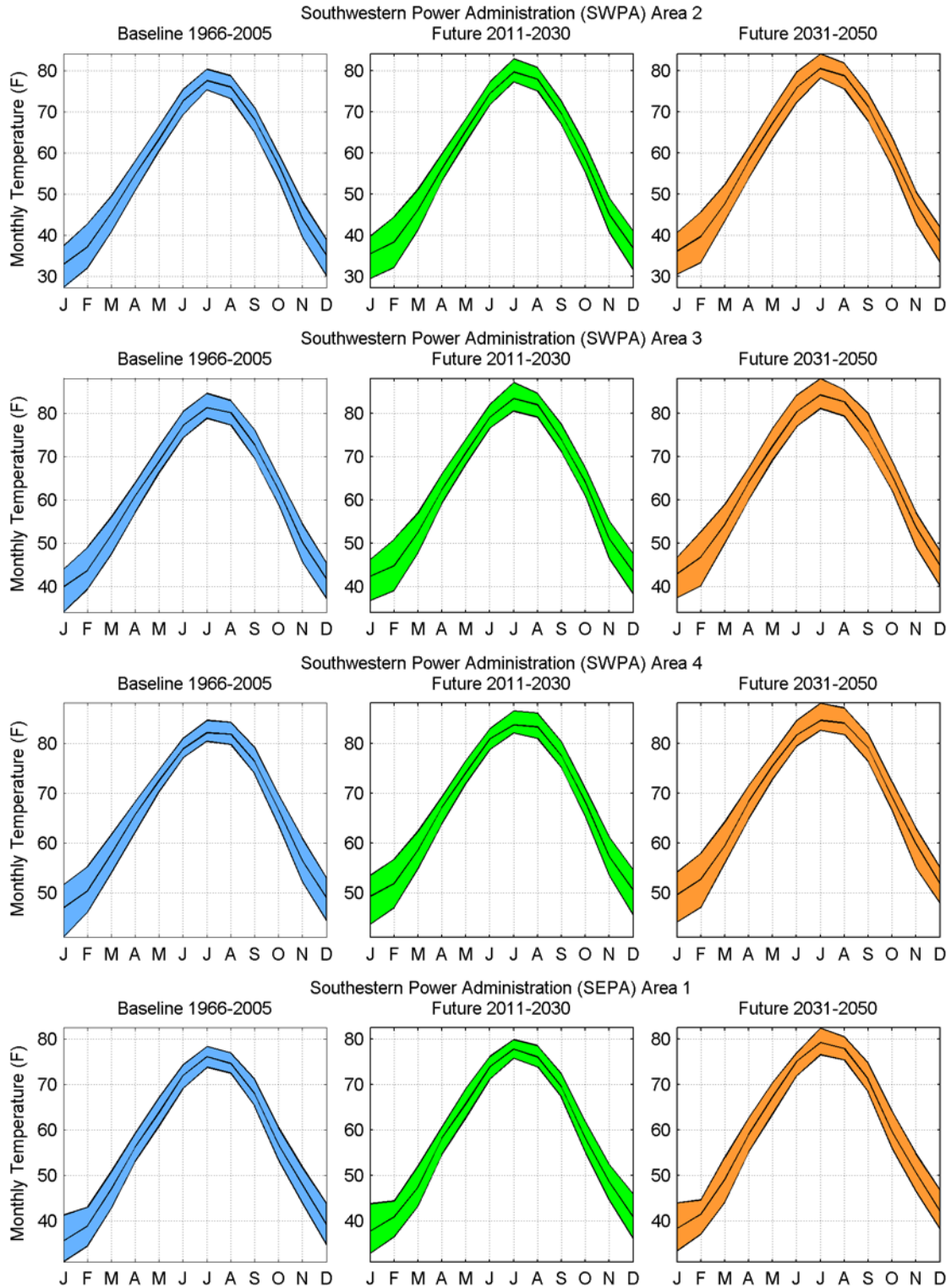
APPENDIX D. VARIABILITY OF MONTHLY TEMPERATURE

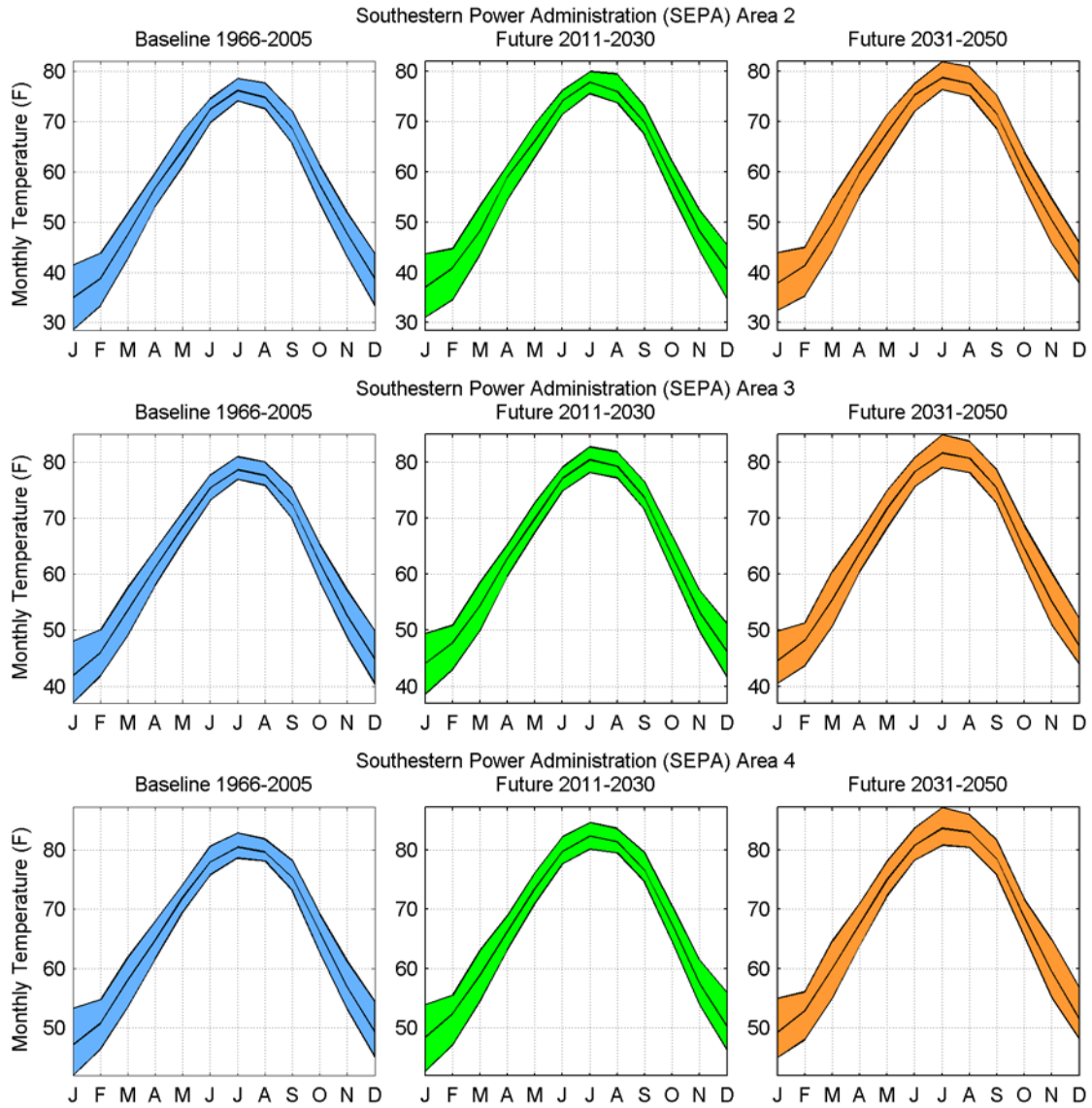
The monthly multi-model 10th, 50th, and 90th percentile temperature across ten climate models are shown for 1966–2005 baseline, 2011–2030 near-term future, and 2031–2050 midterm future periods for all PMA study areas.







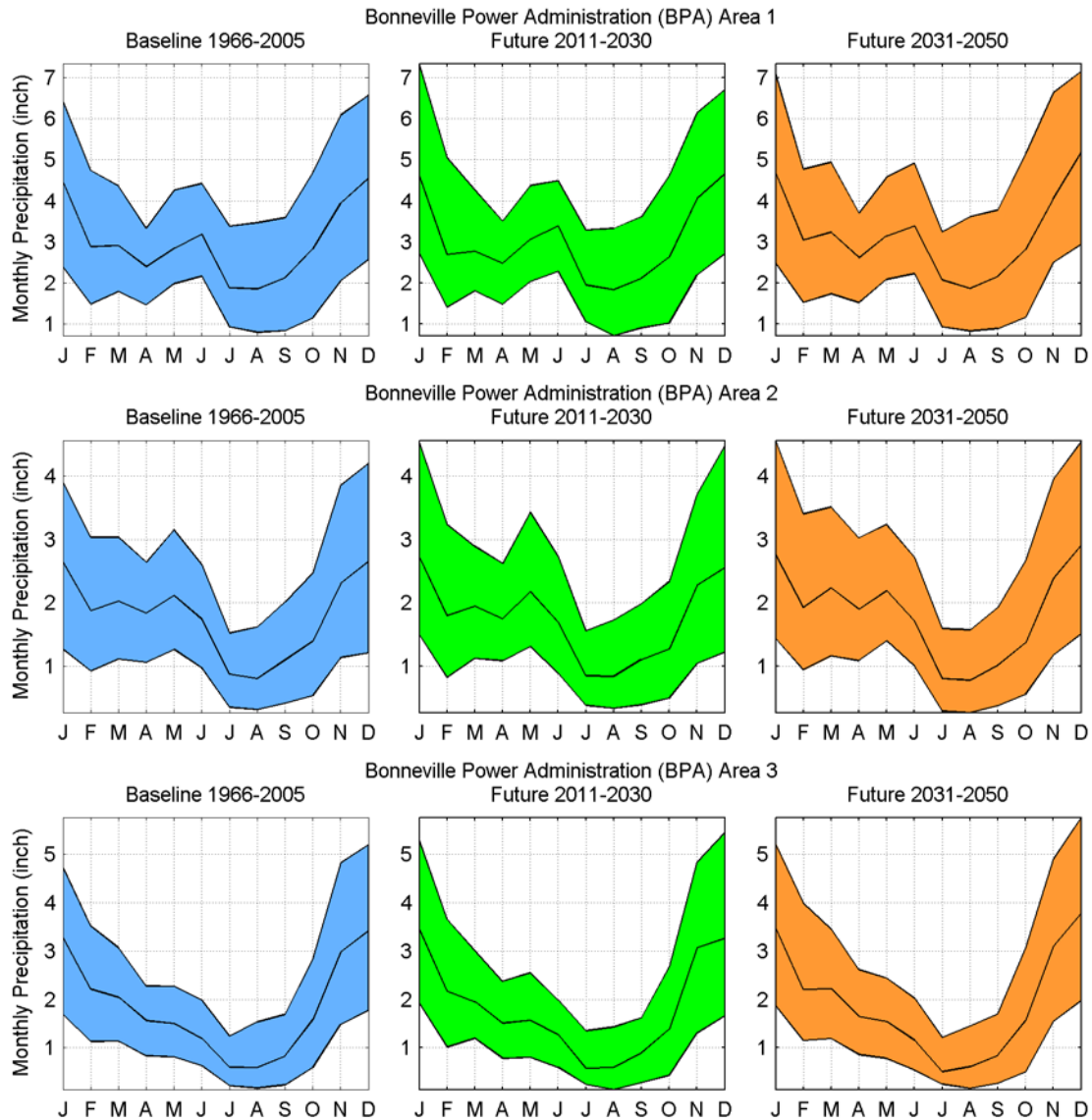


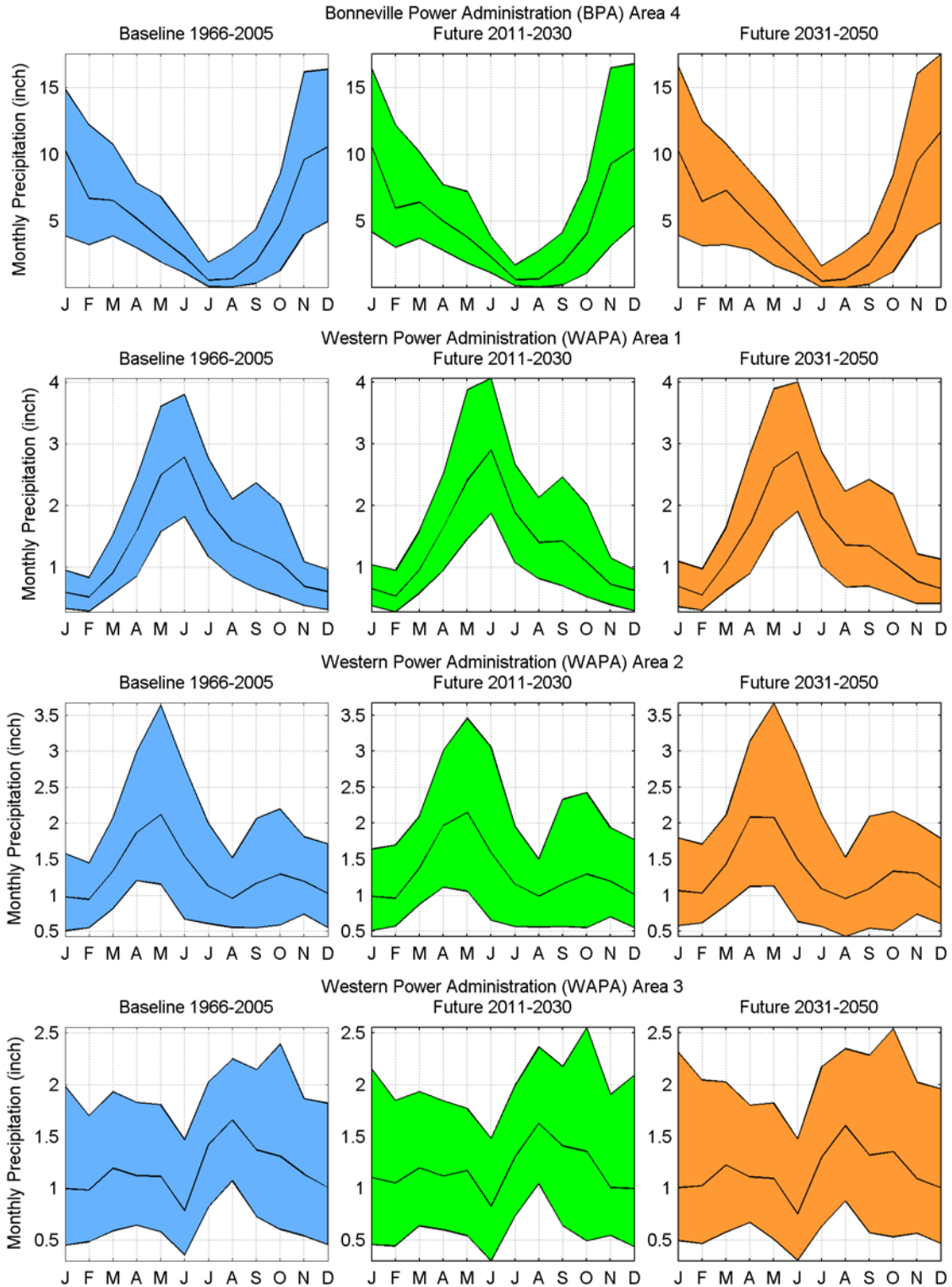


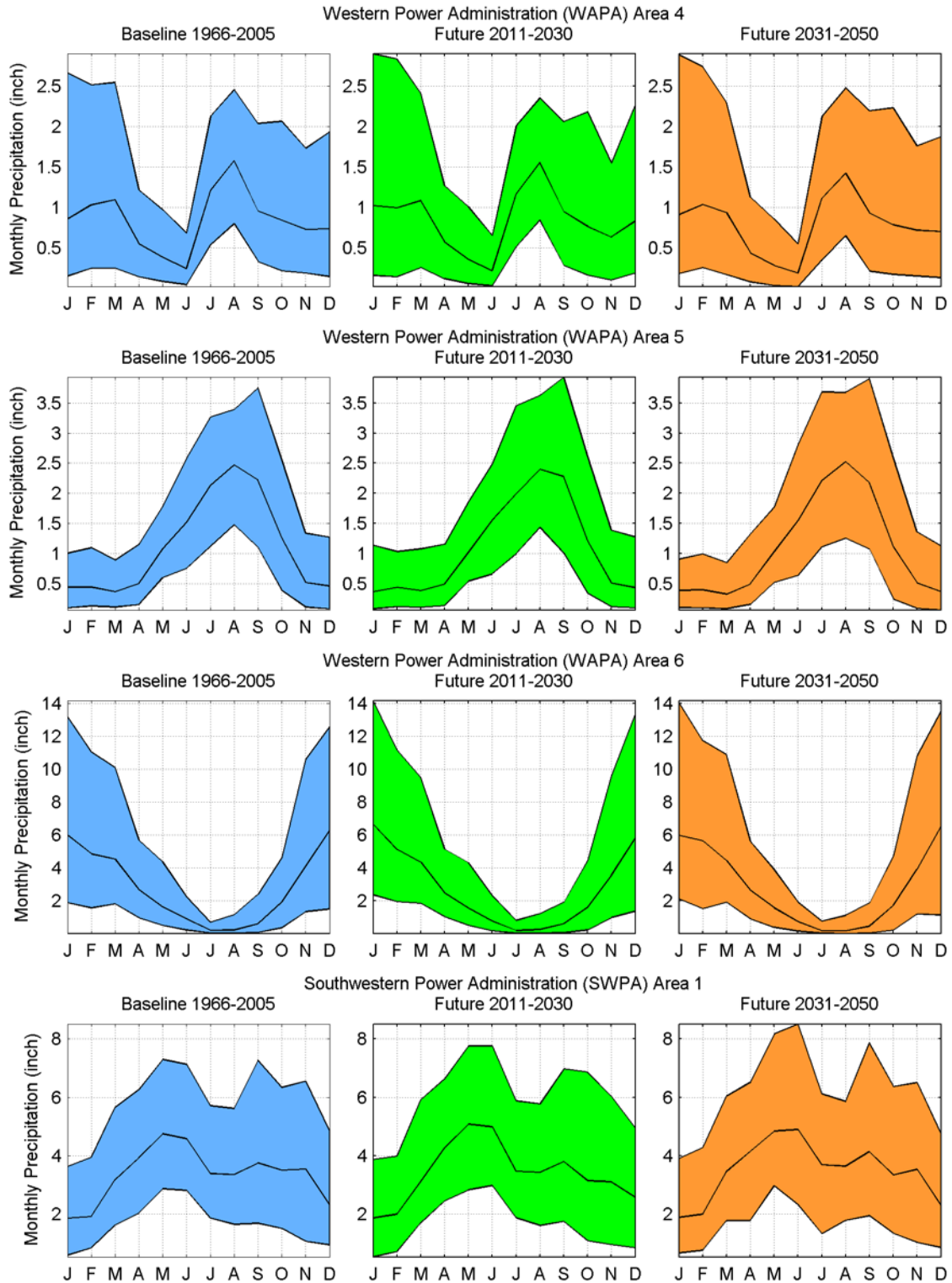
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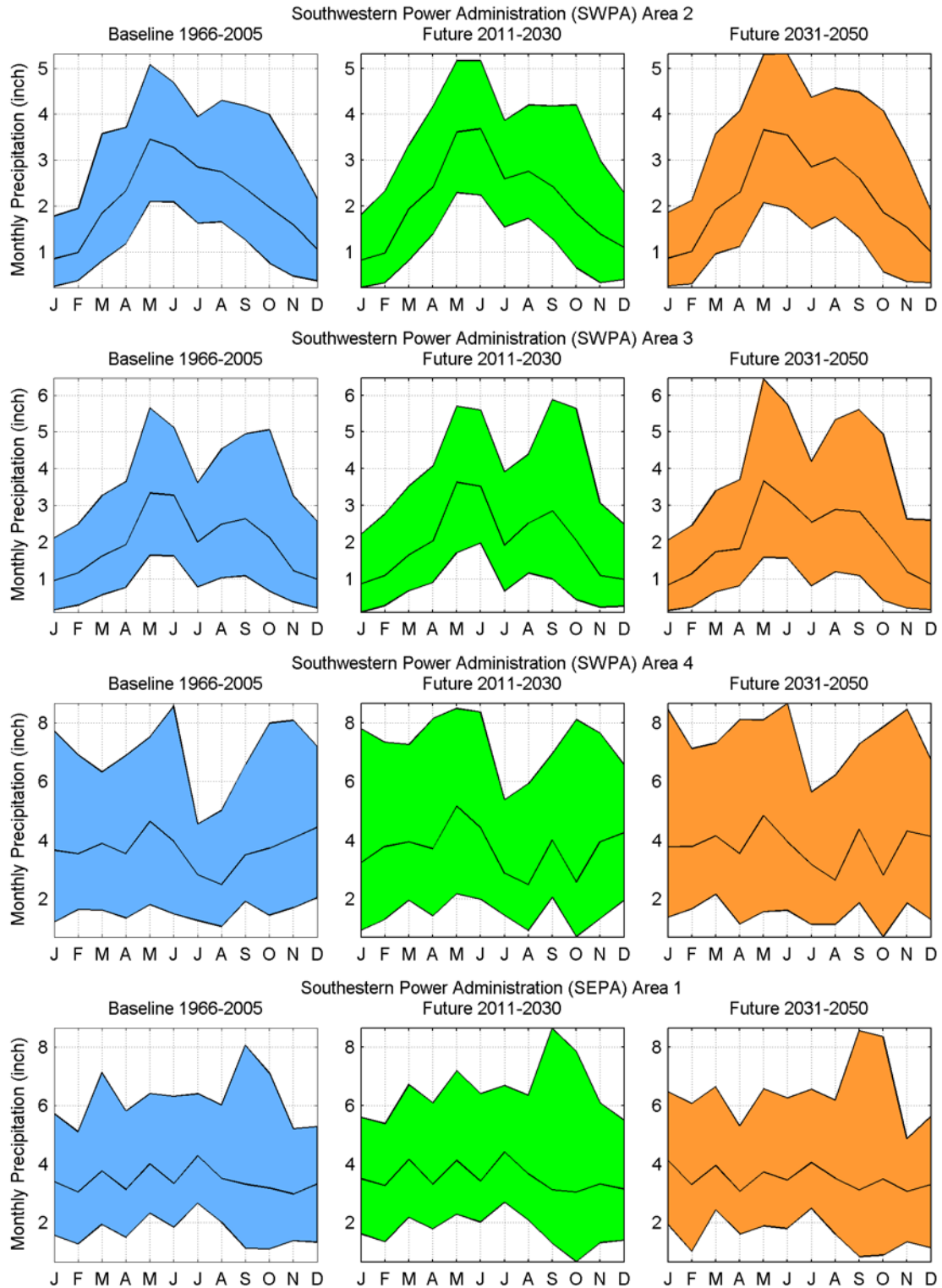
APPENDIX E. VARIABILITY OF MONTHLY PRECIPITATION

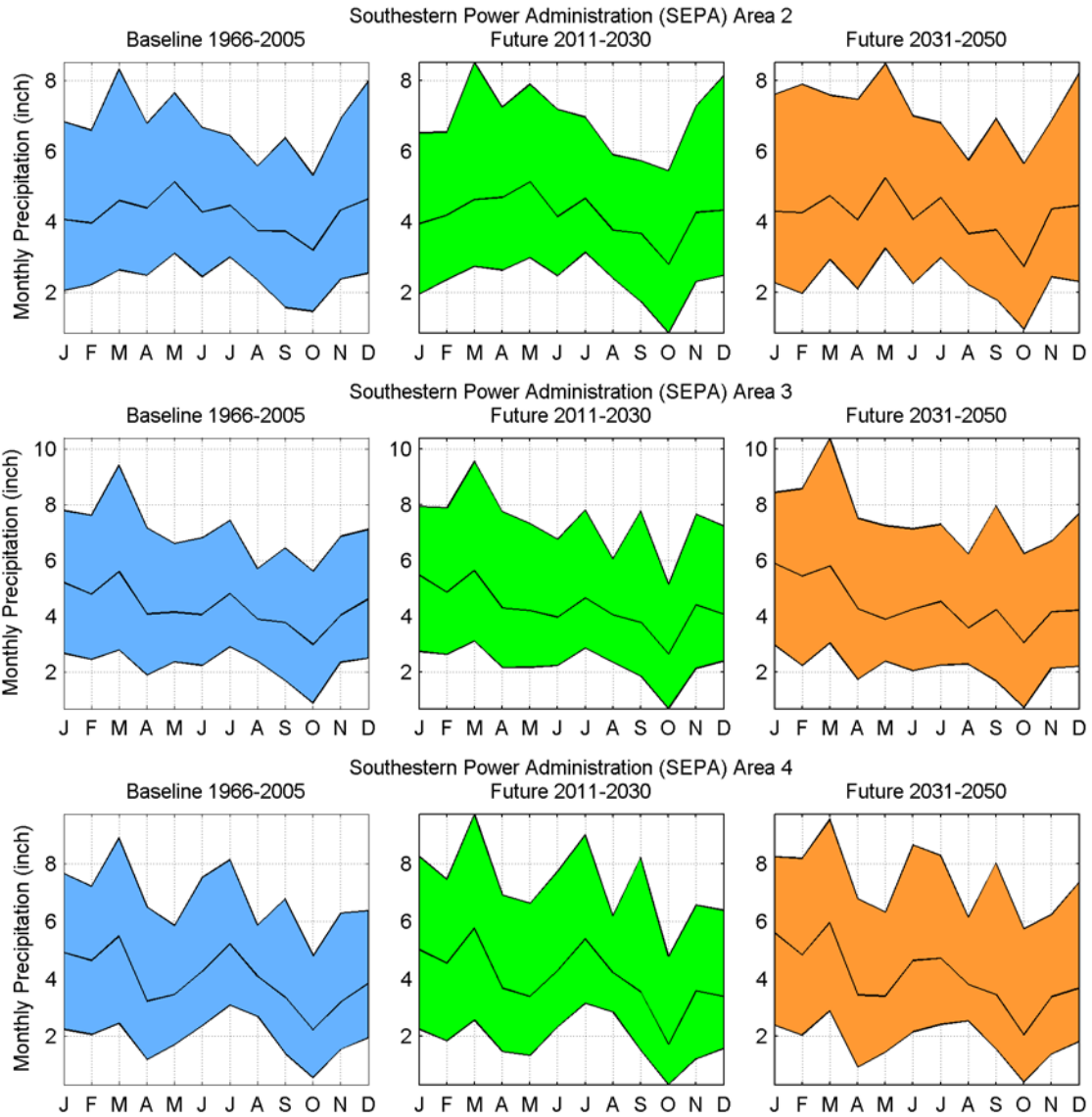
The monthly multi-model 10th, 50th, and 90th percentile precipitation across ten climate models are shown for 1966–2005 baseline, 2011–2030 near-term future, and 2031–2050 midterm future periods for all PMA study areas.







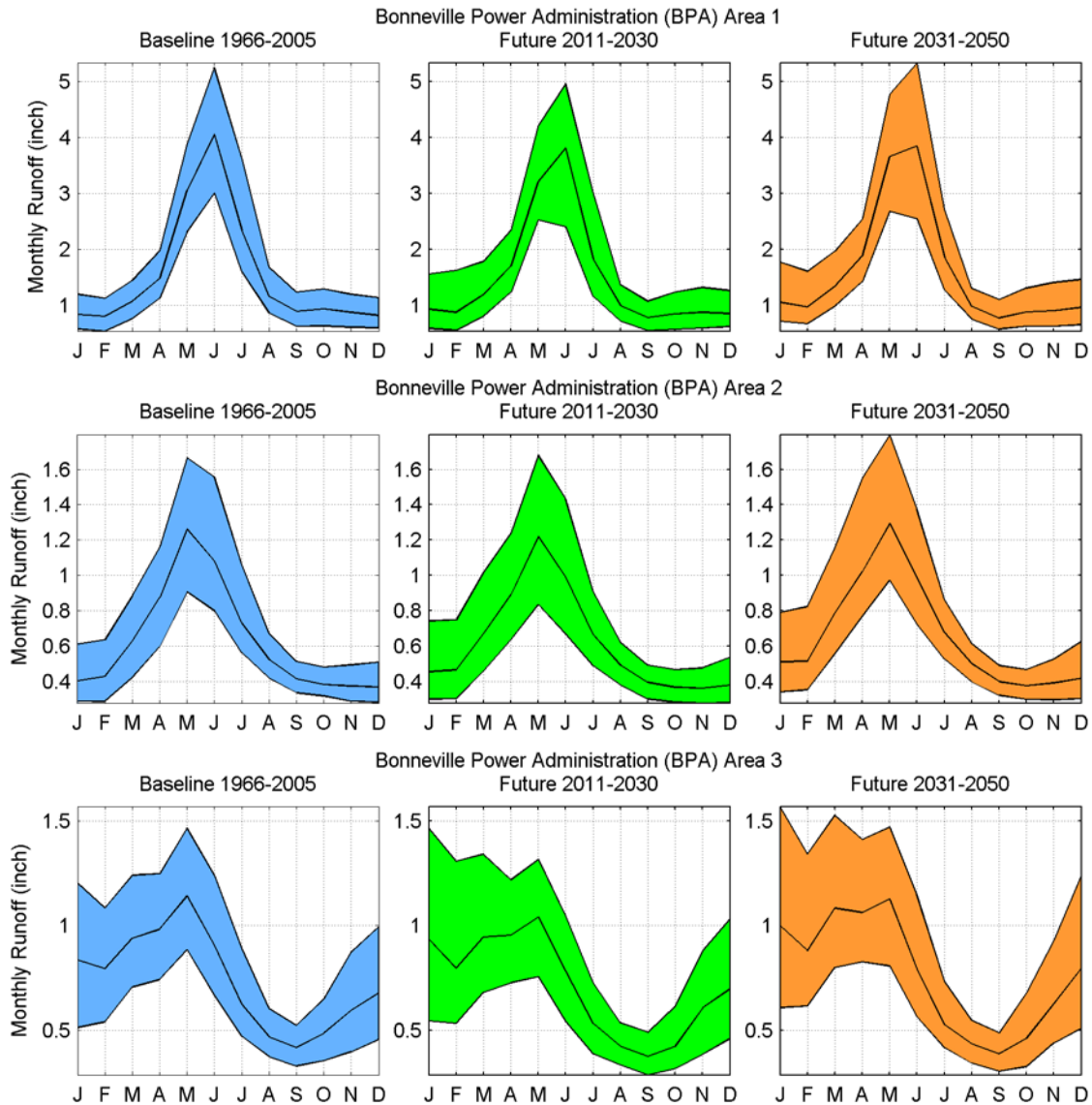


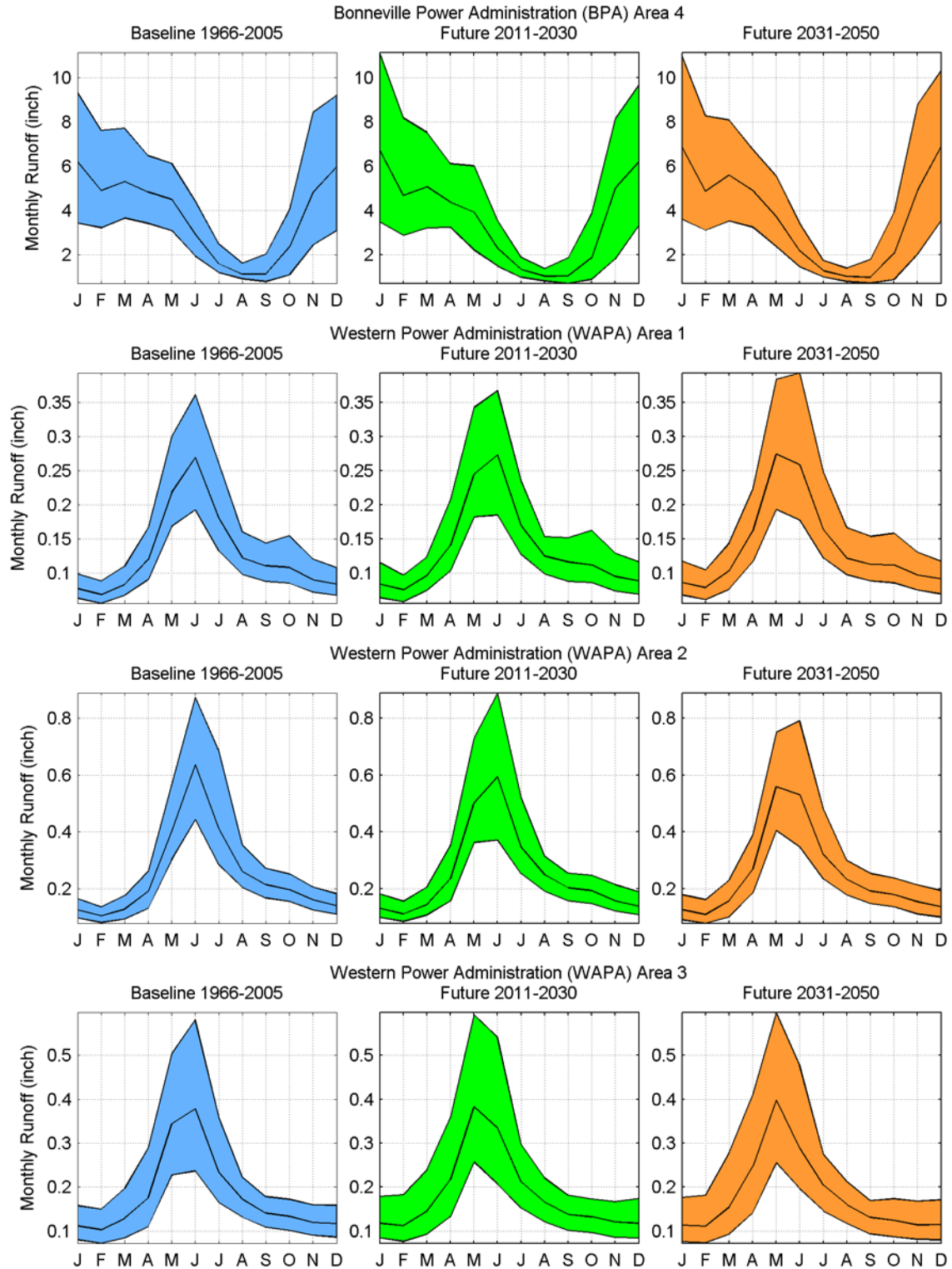


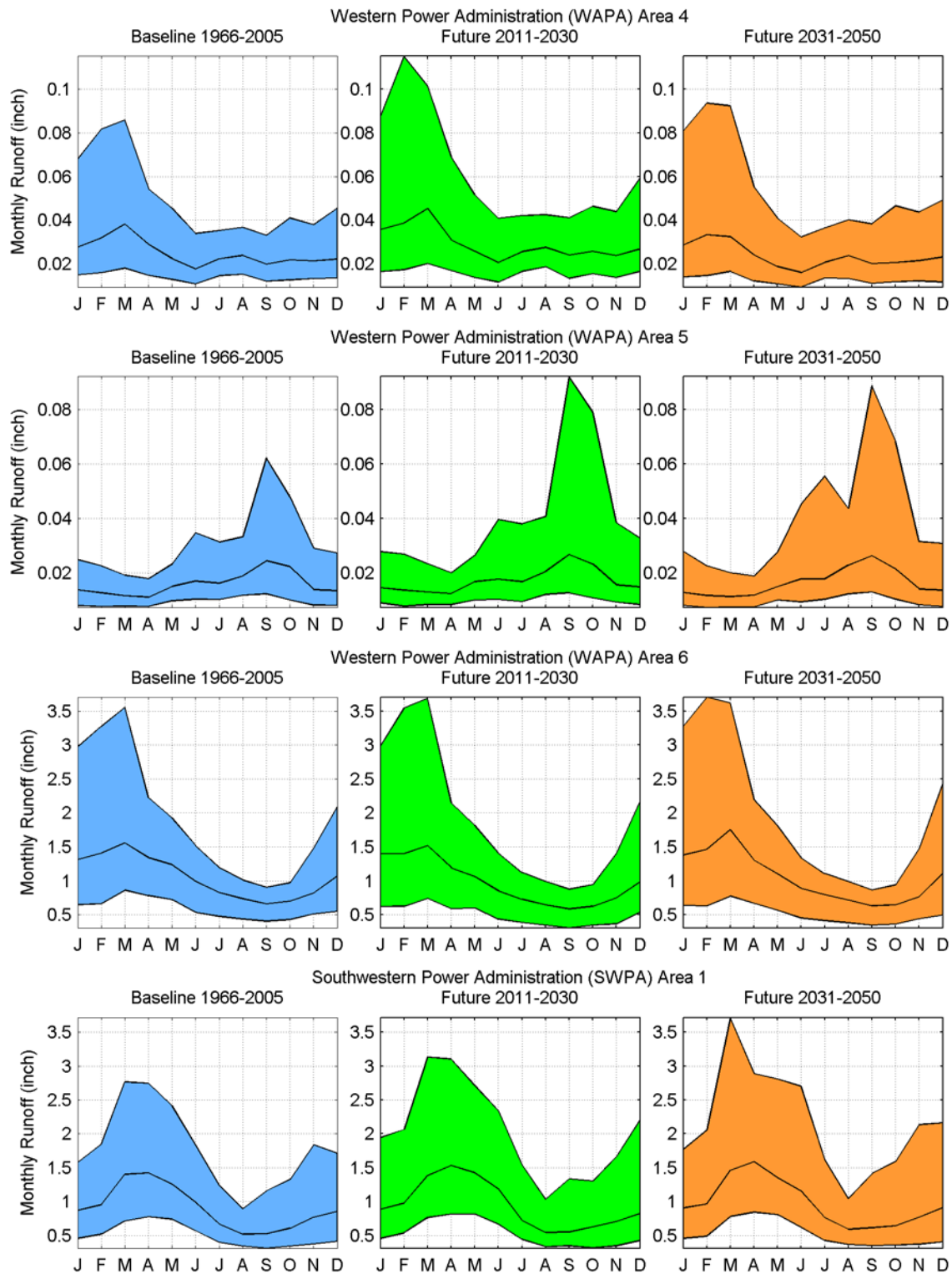
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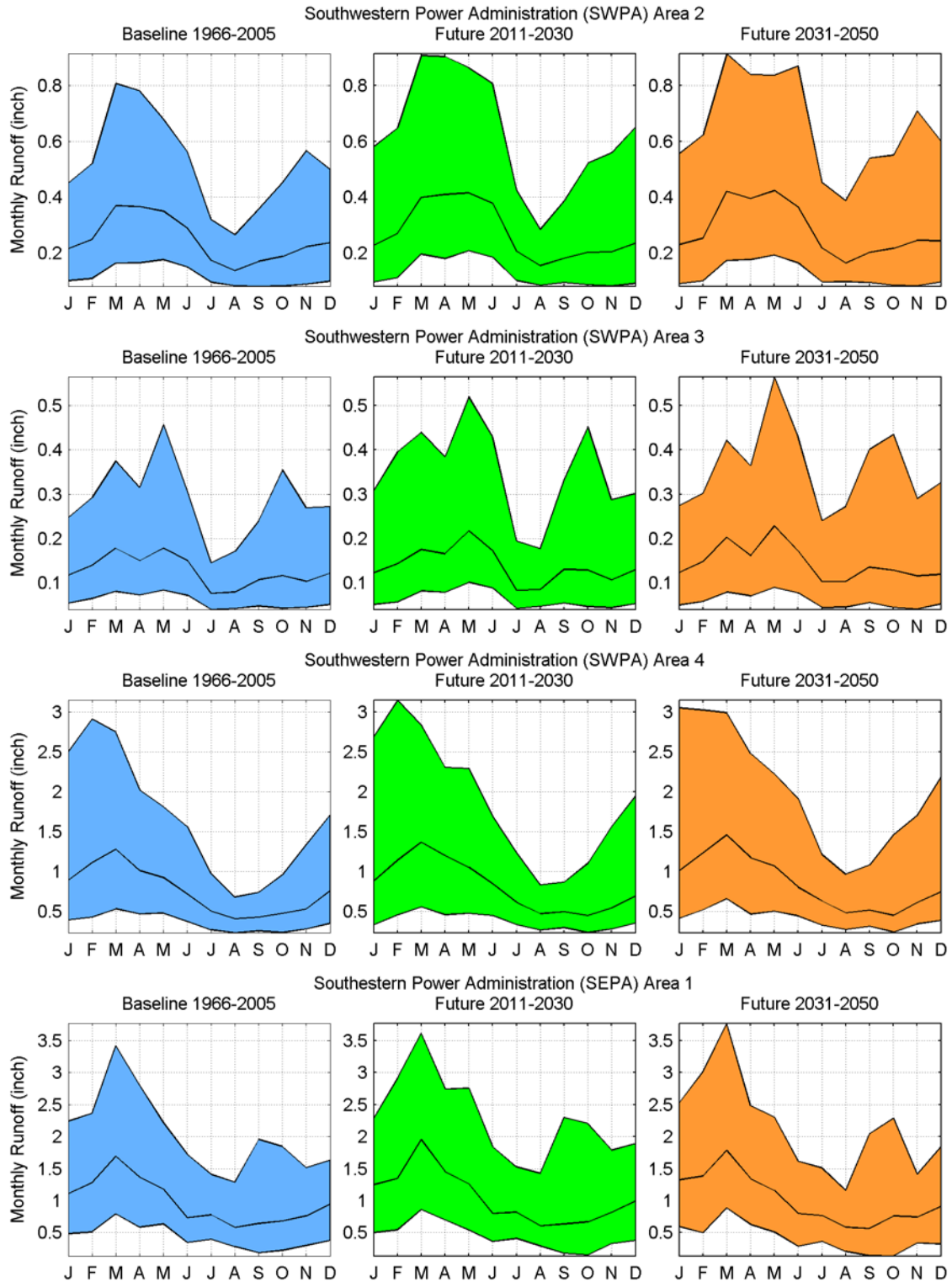
APPENDIX F. VARIABILITY OF MONTHLY RUNOFF

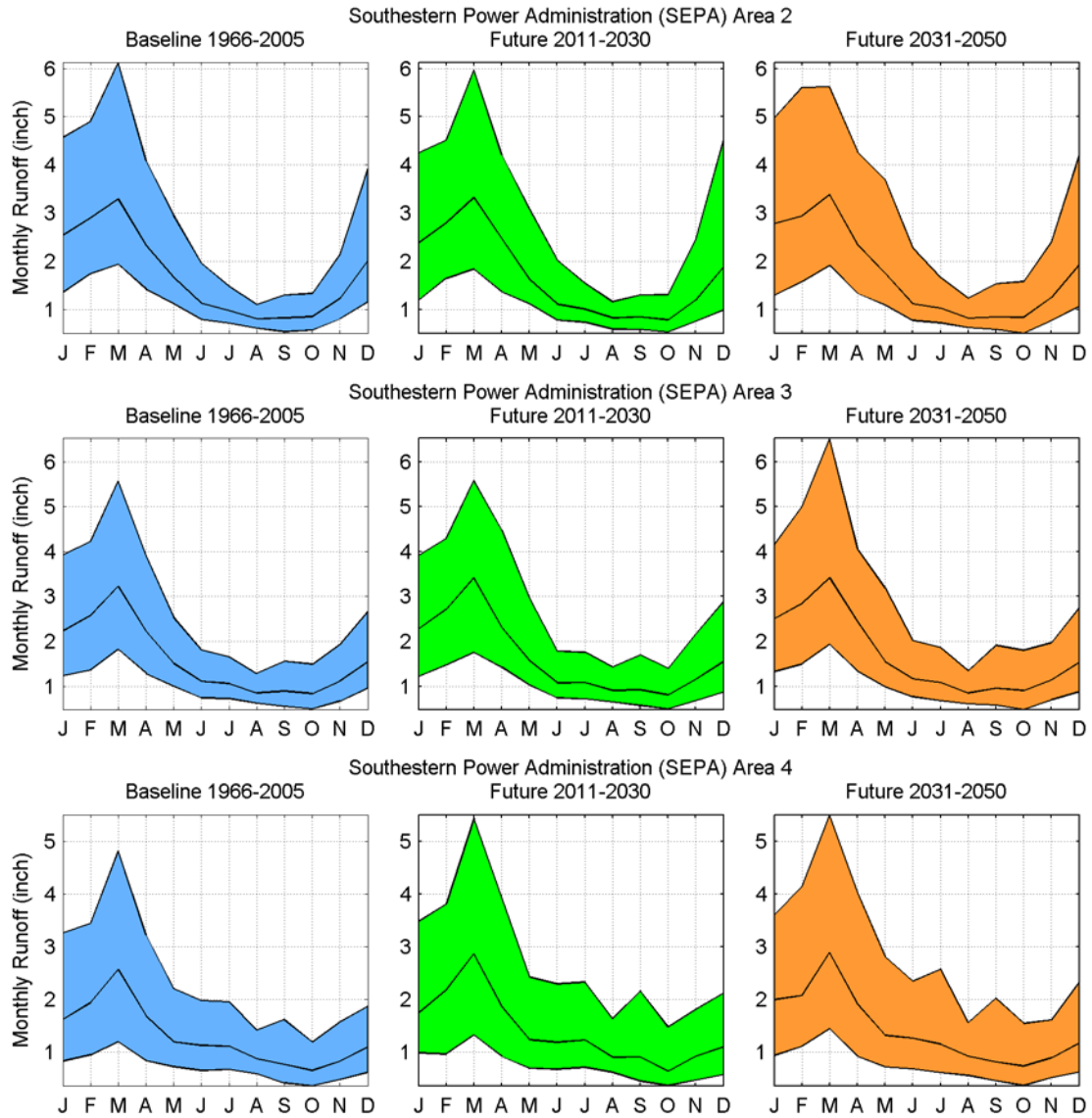
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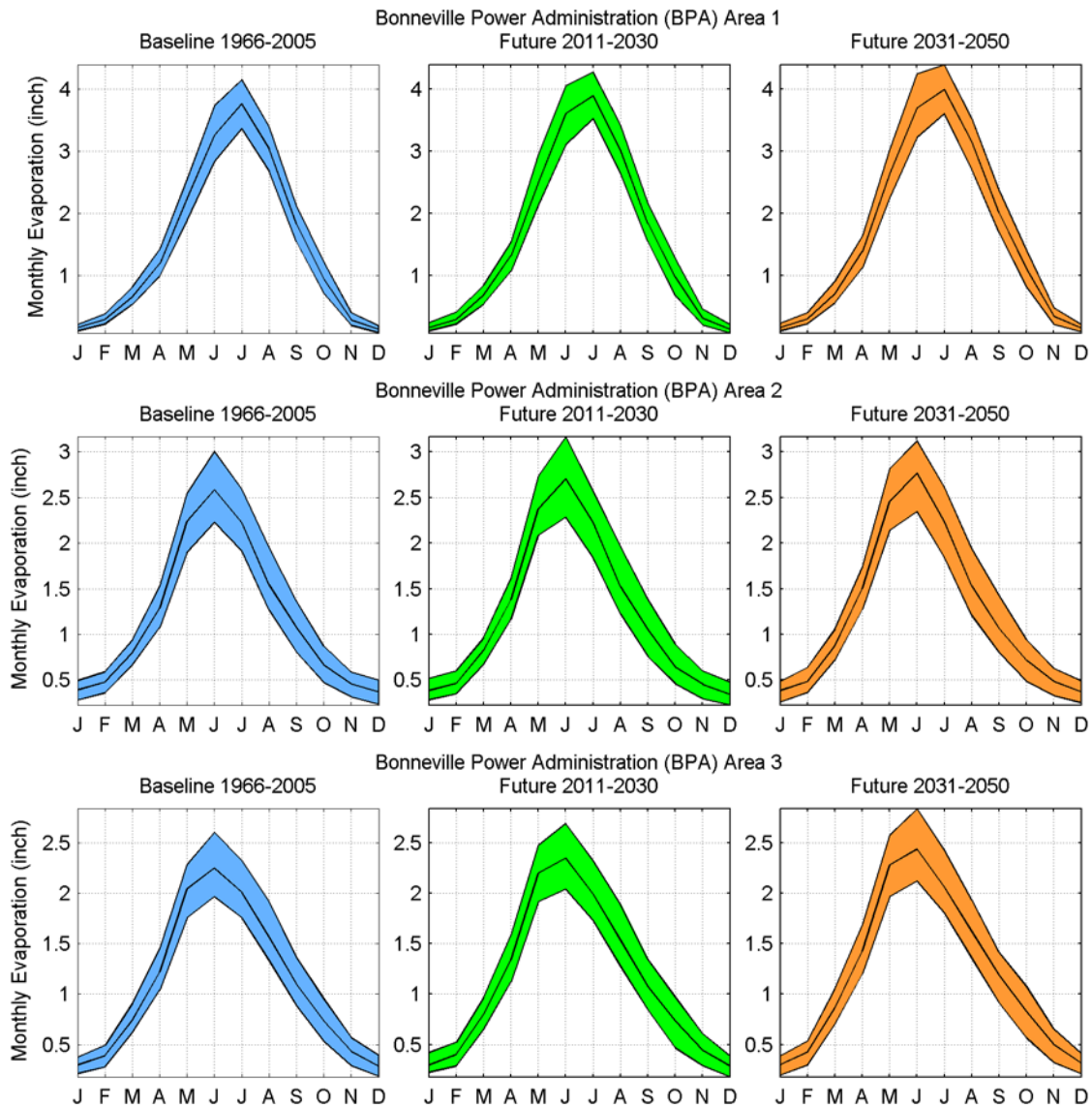


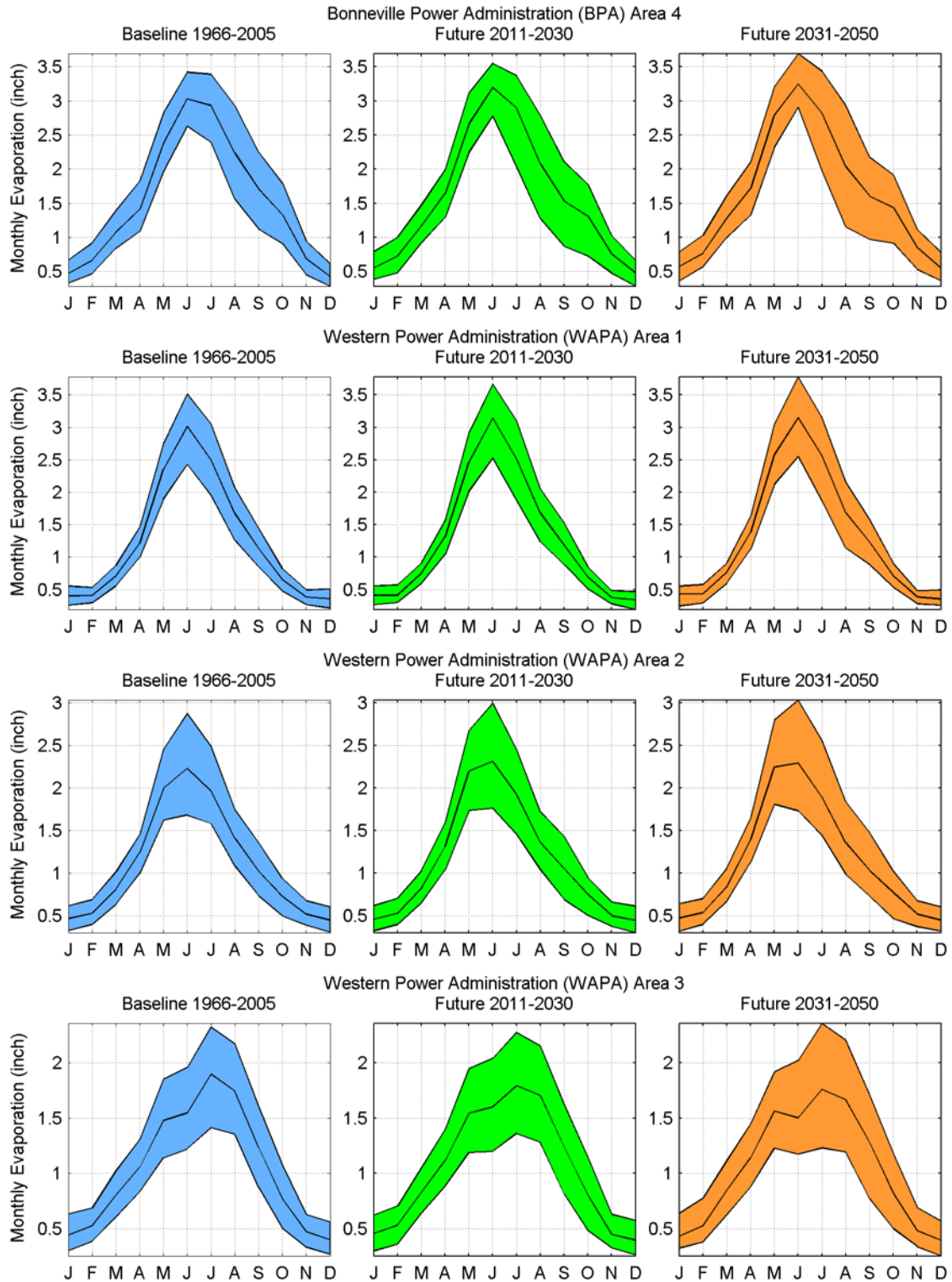


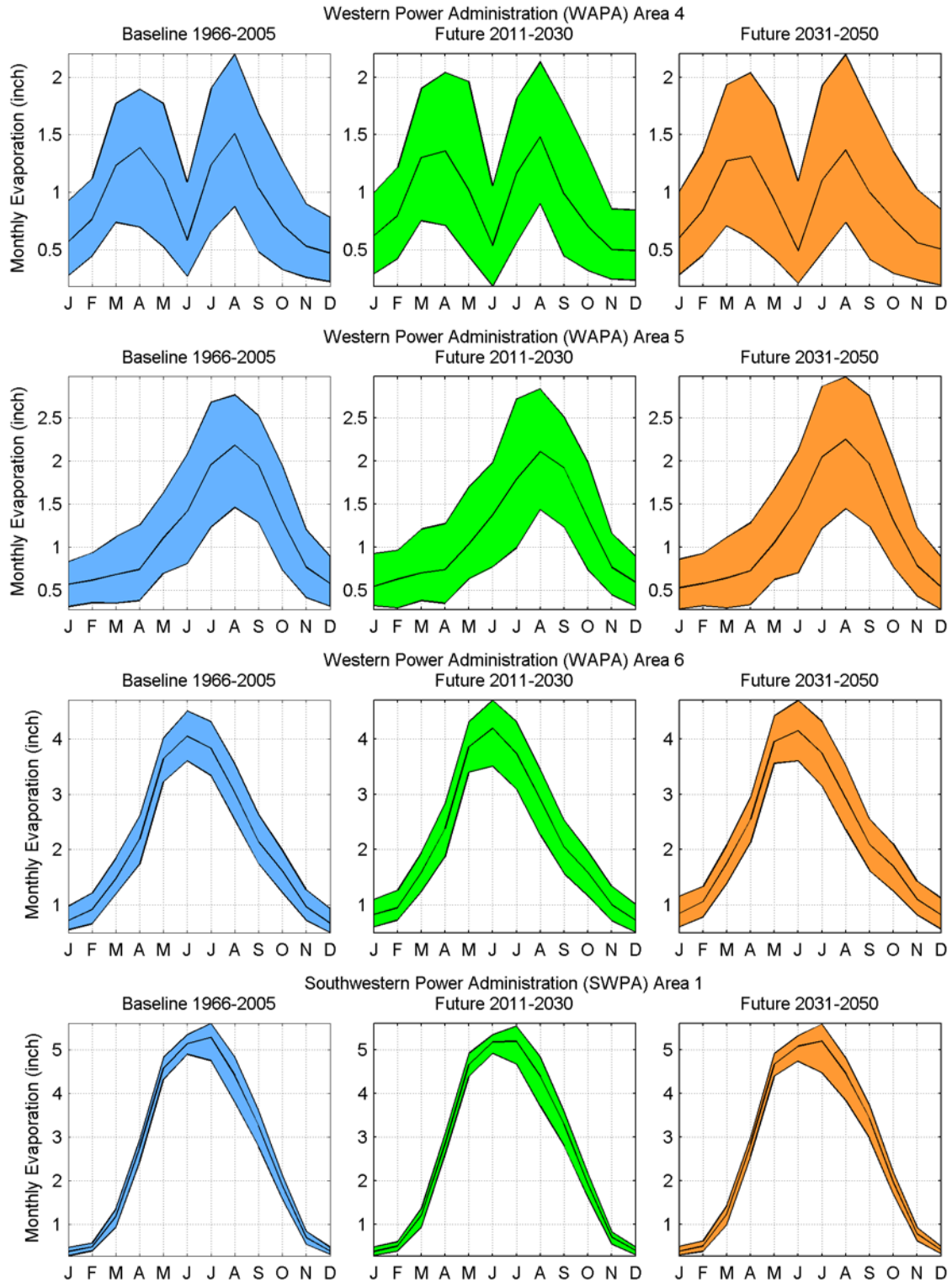
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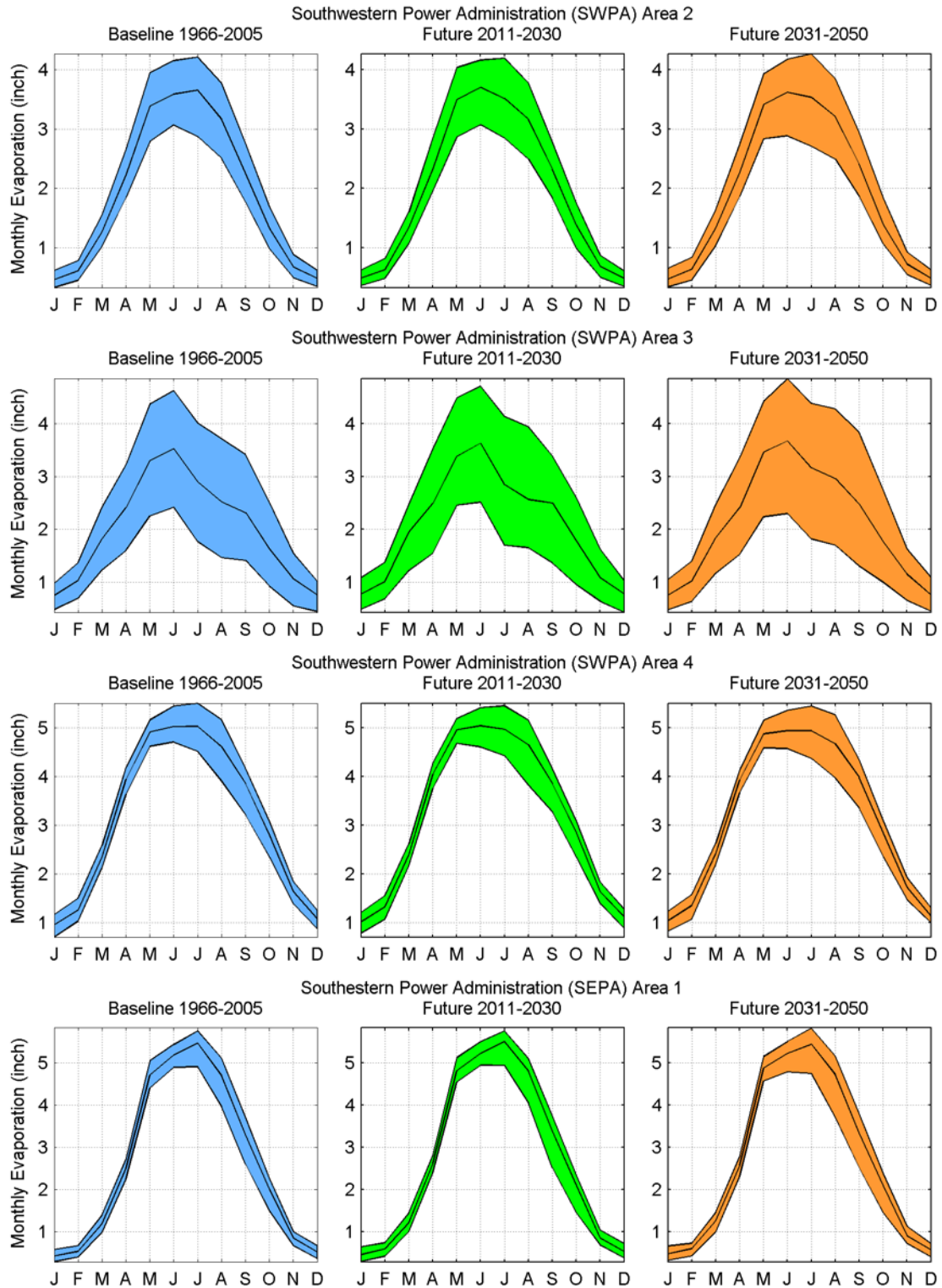
APPENDIX G. VARIABILITY OF MONTHLY EVAPOTRANSPIRATION

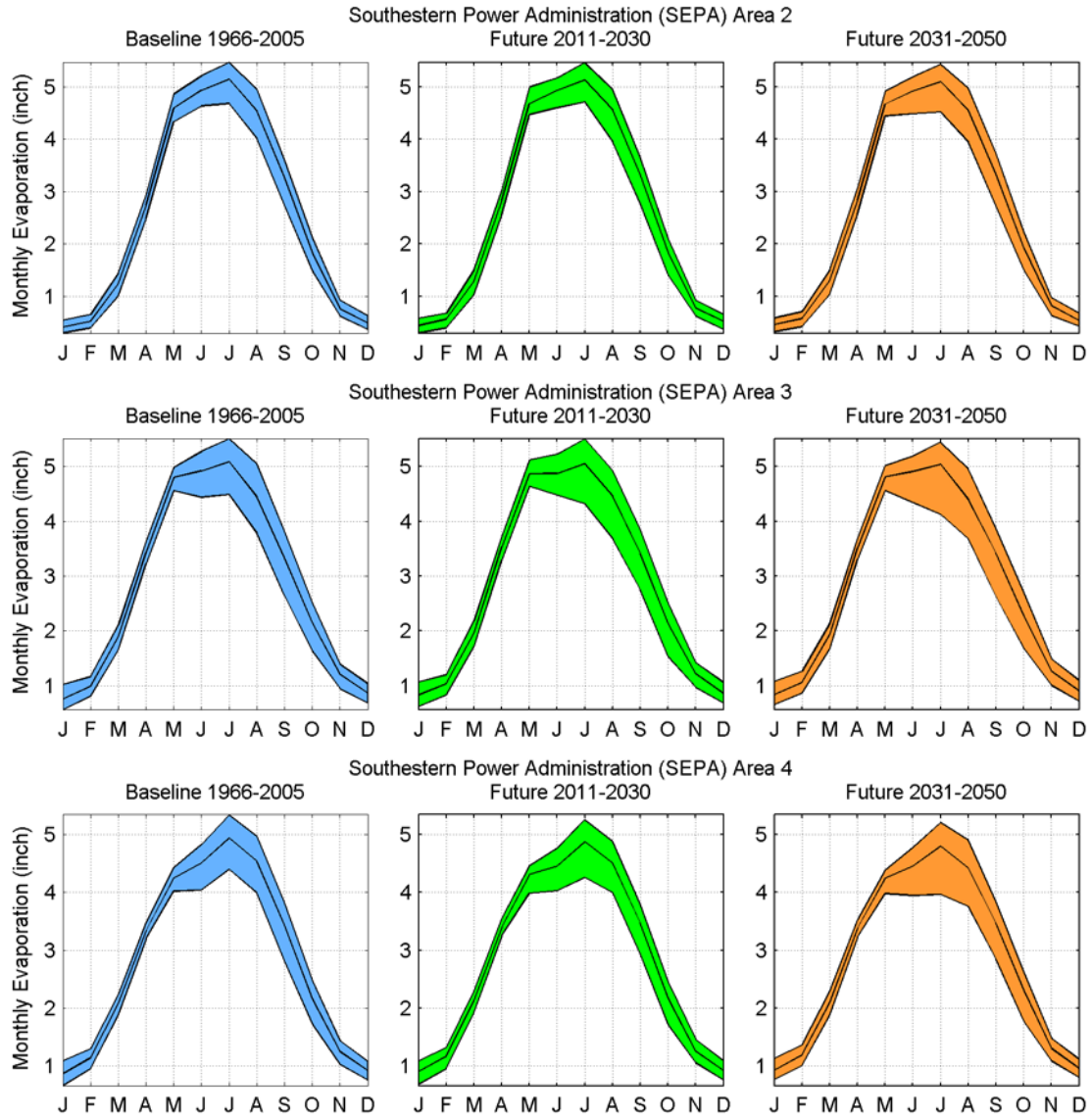
The monthly multi-model 10th, 50th, and 90th percentile evapotranspiration across ten climate models are showed for 1966–2005 baseline, 2011–2030 near-term future, and 2031–2050 midterm future periods for all PMA study areas.







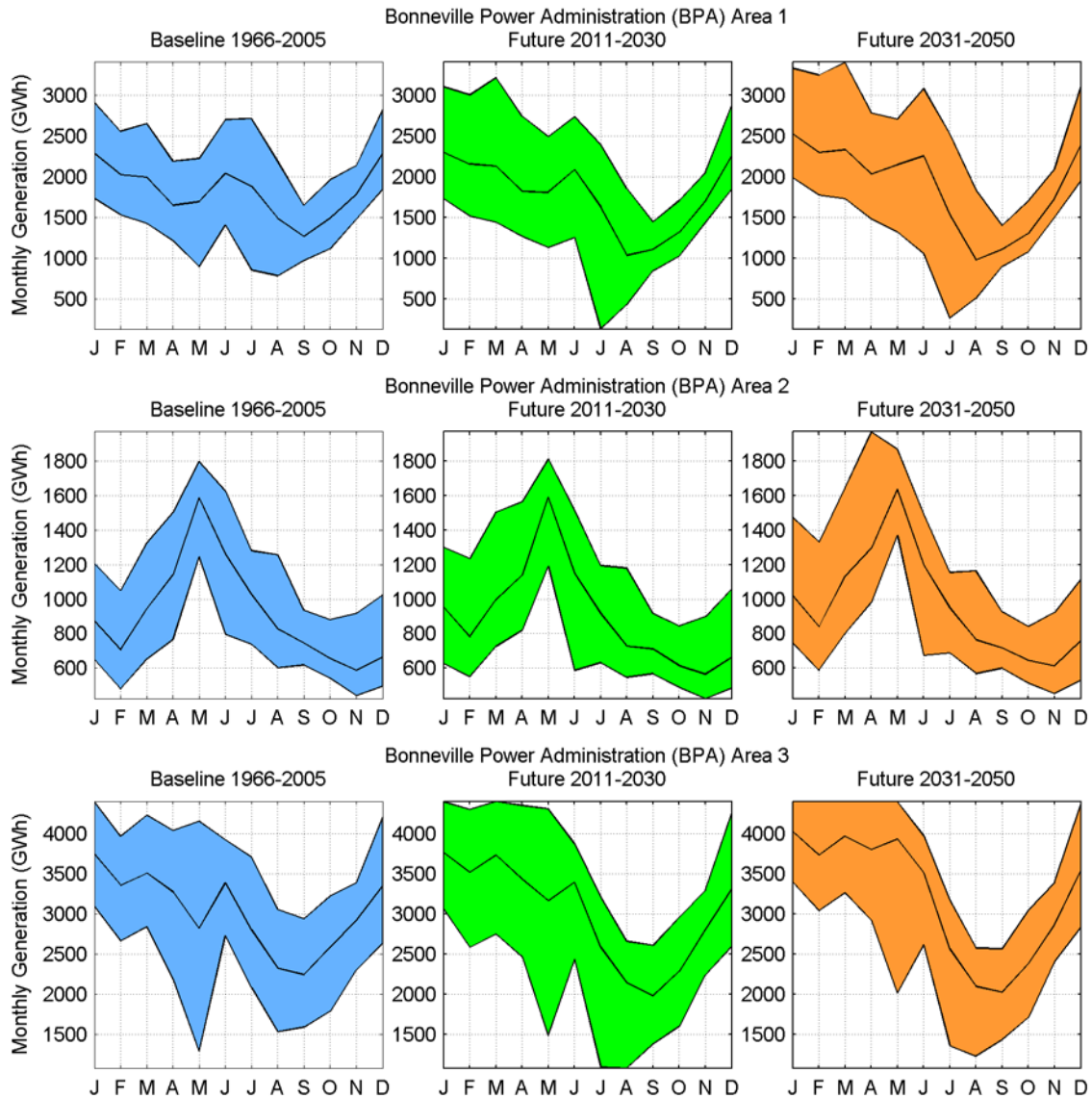


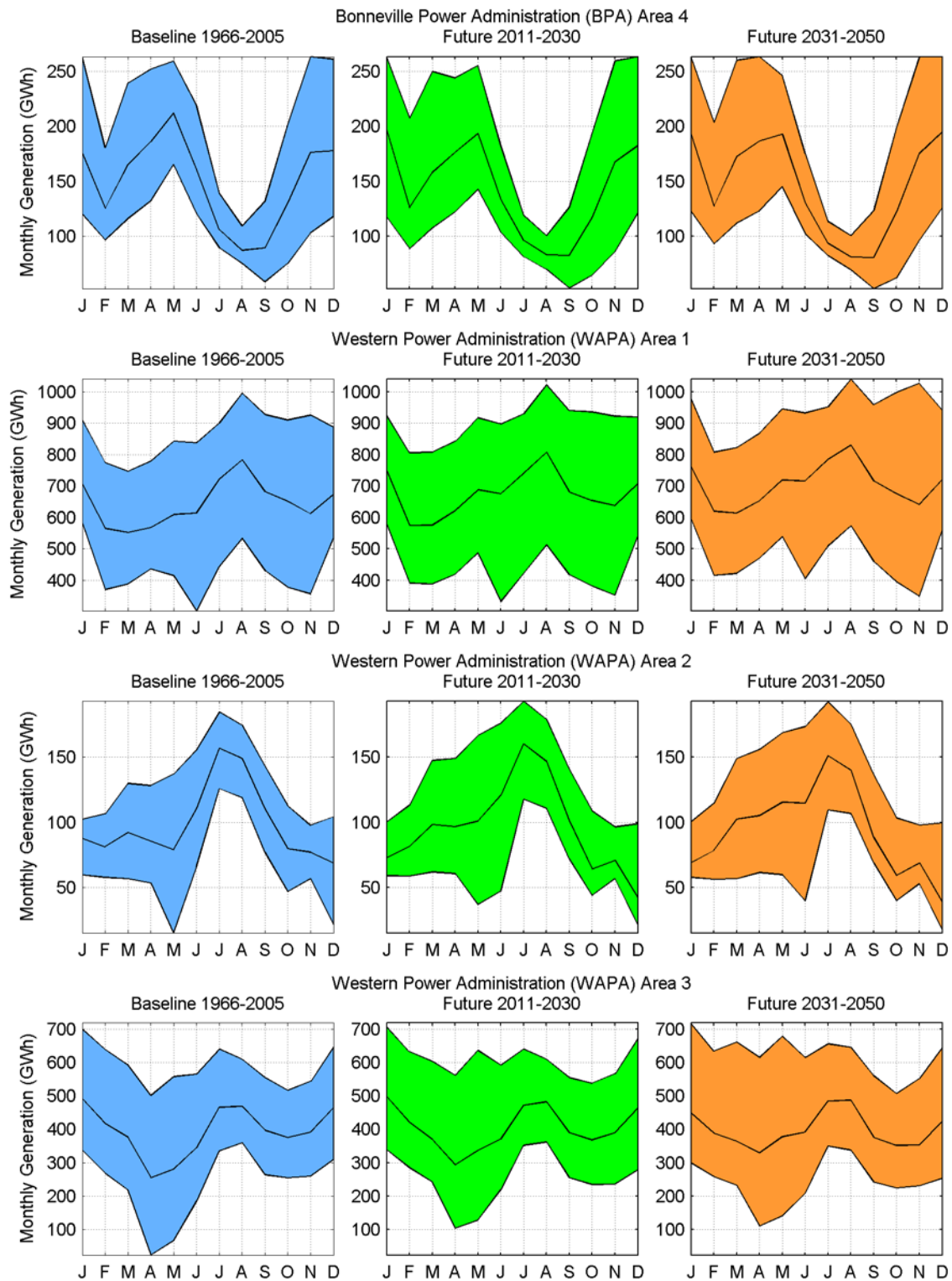


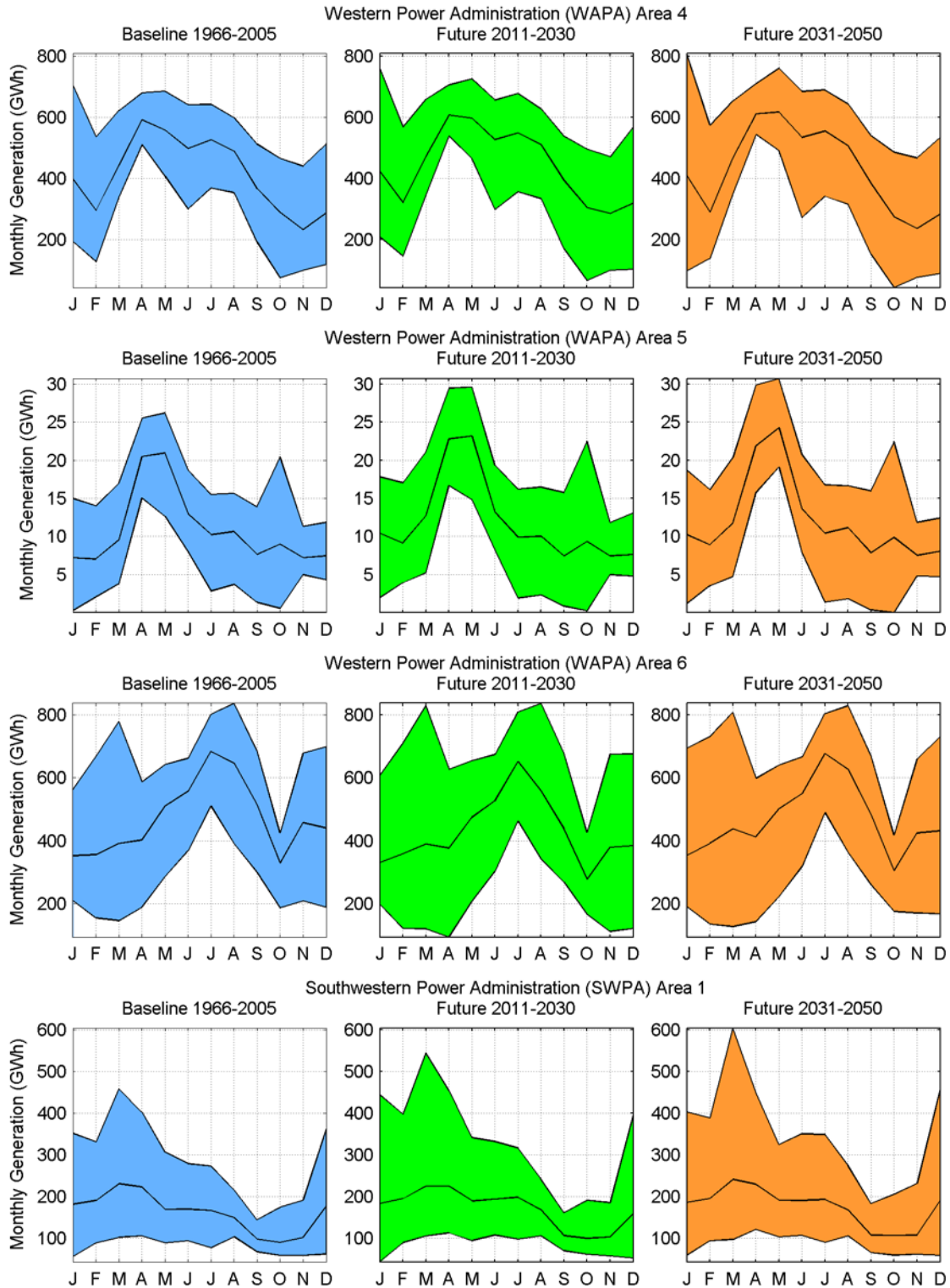
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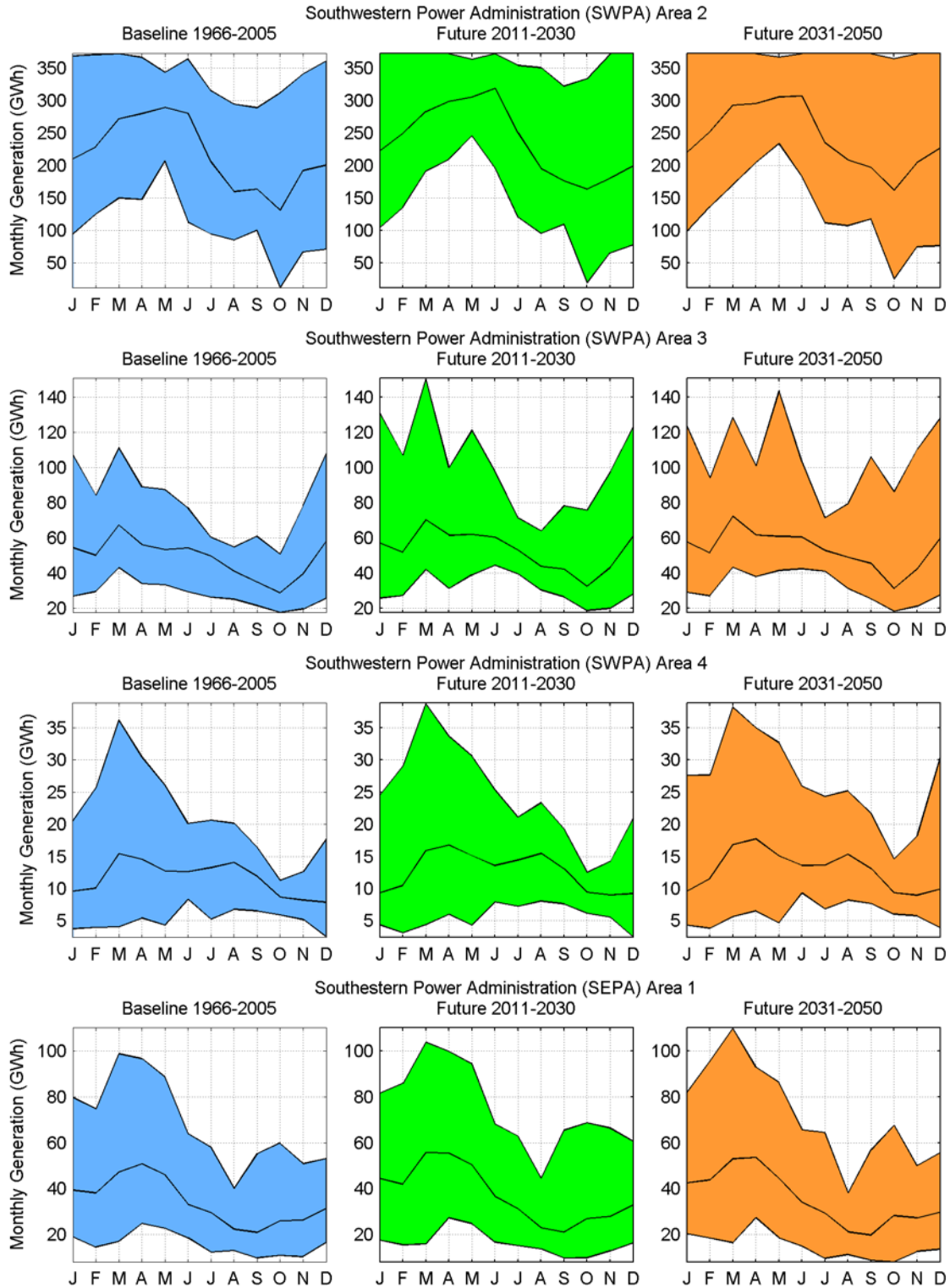
APPENDIX H. VARIABILITY OF MONTHLY GENERATION

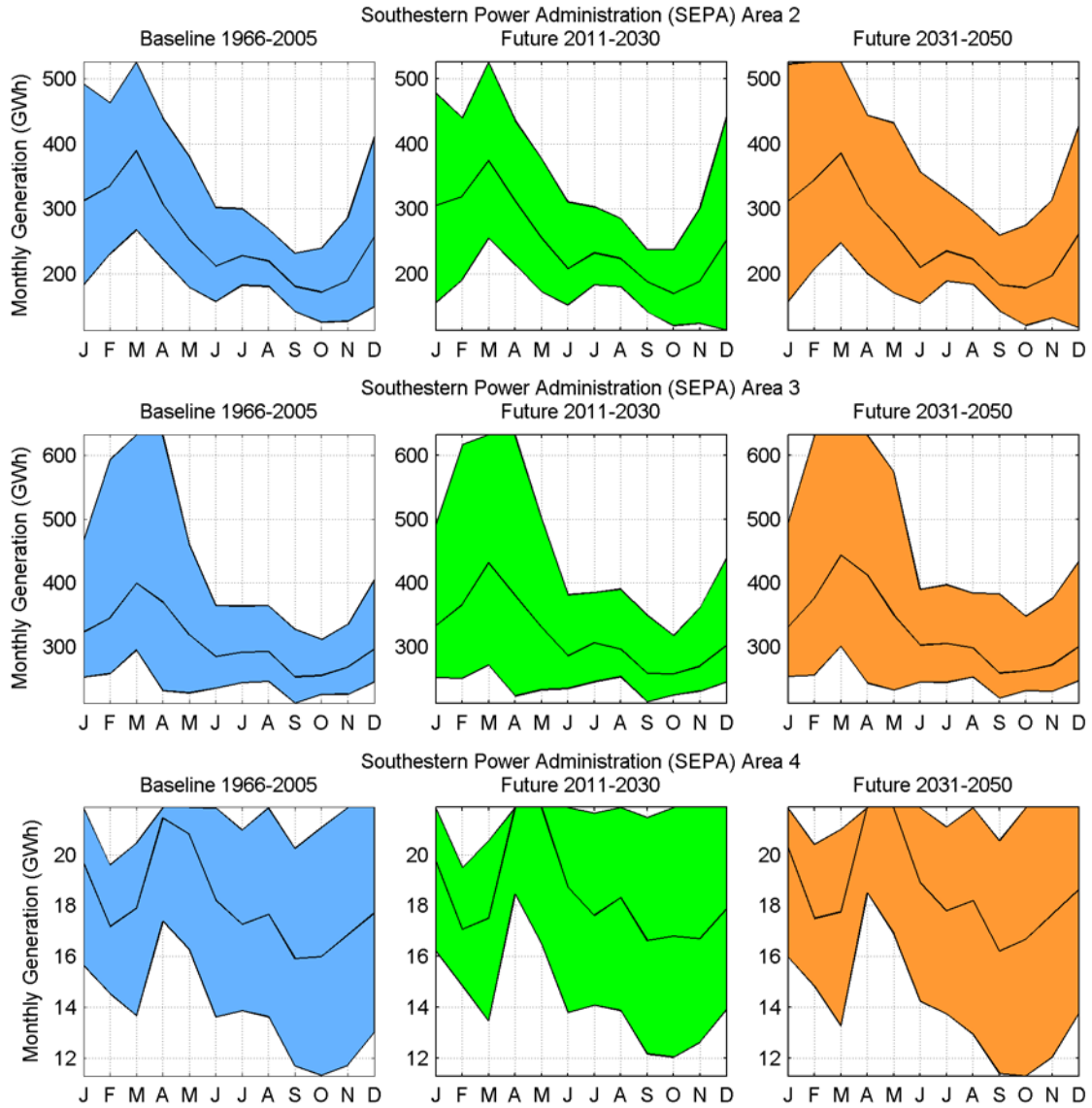
The monthly multi-model 10th, 50th, and 90th percentile generation across ten climate models are showed for 1966–2005 baseline, 2011–2030 near-term future, and 2031–2050 midterm future periods for all PMA study areas.







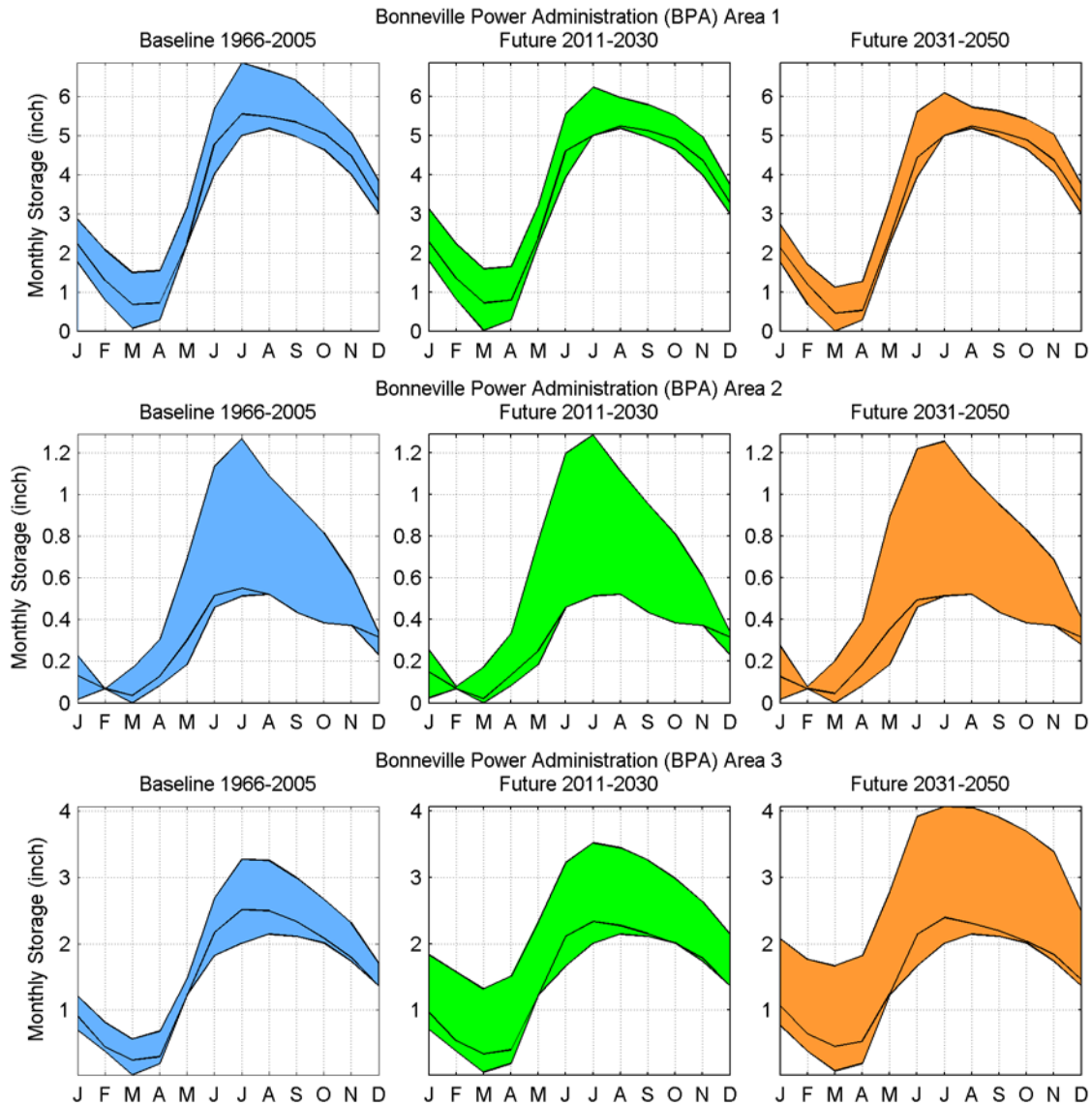


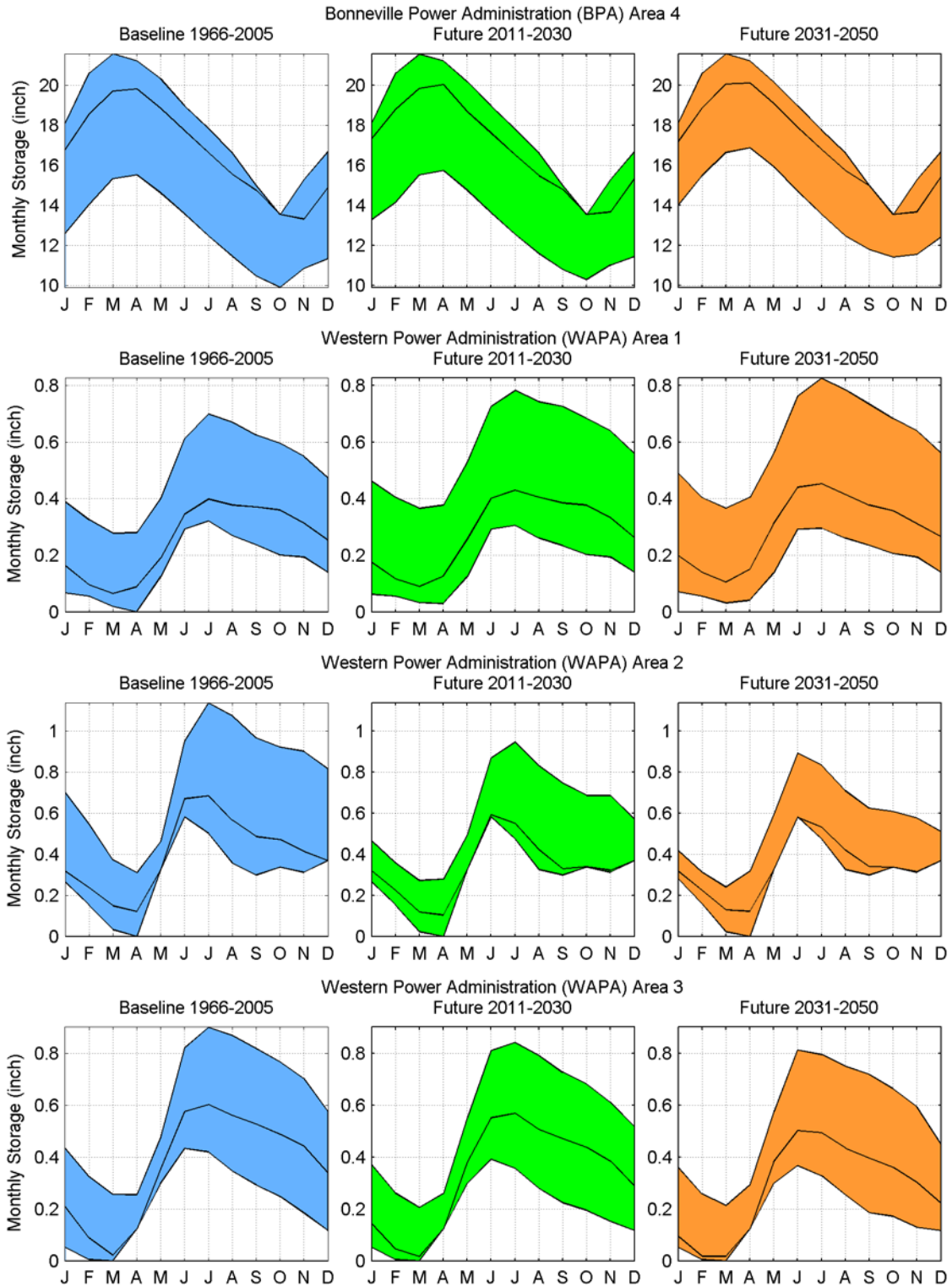


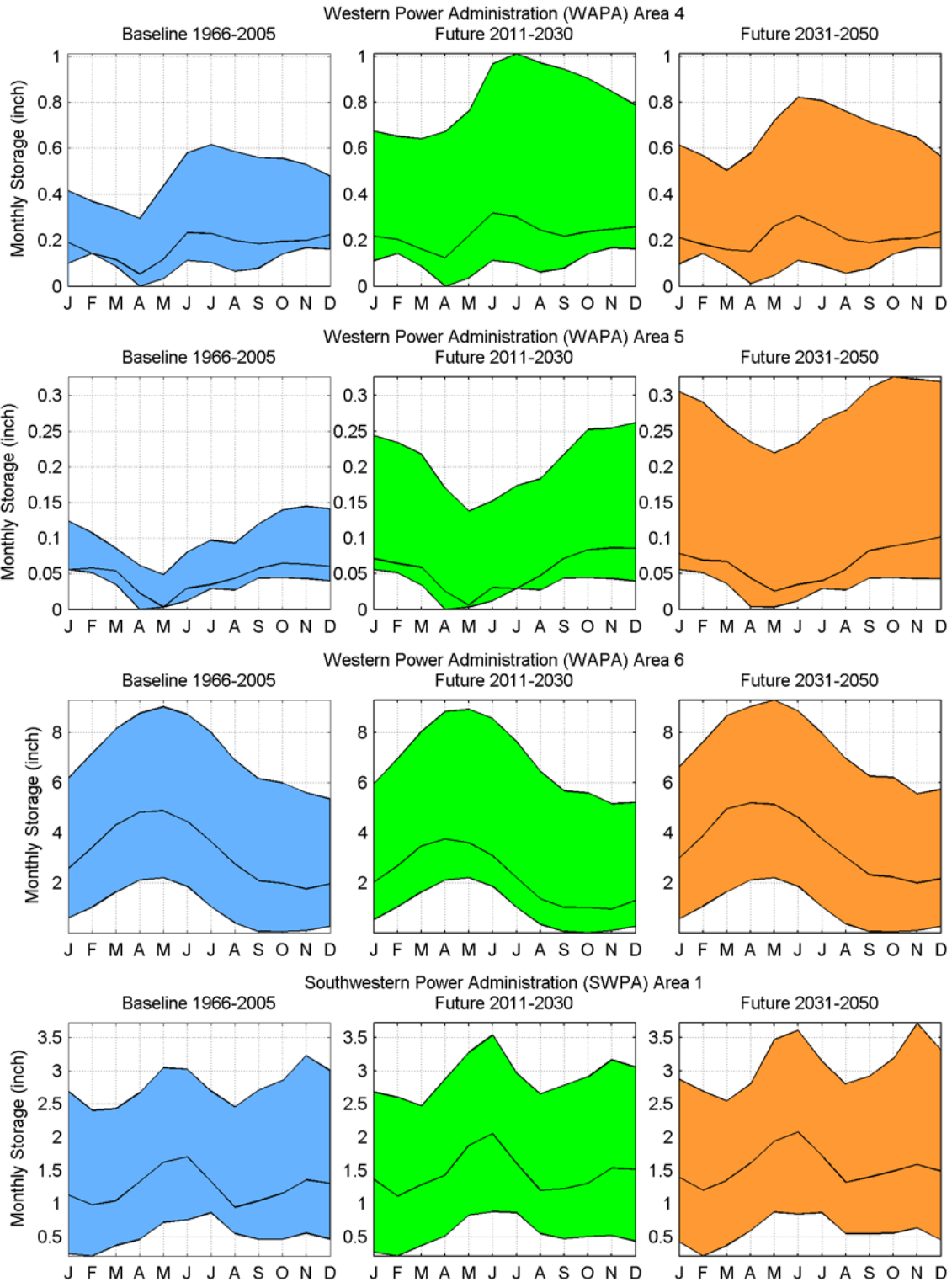
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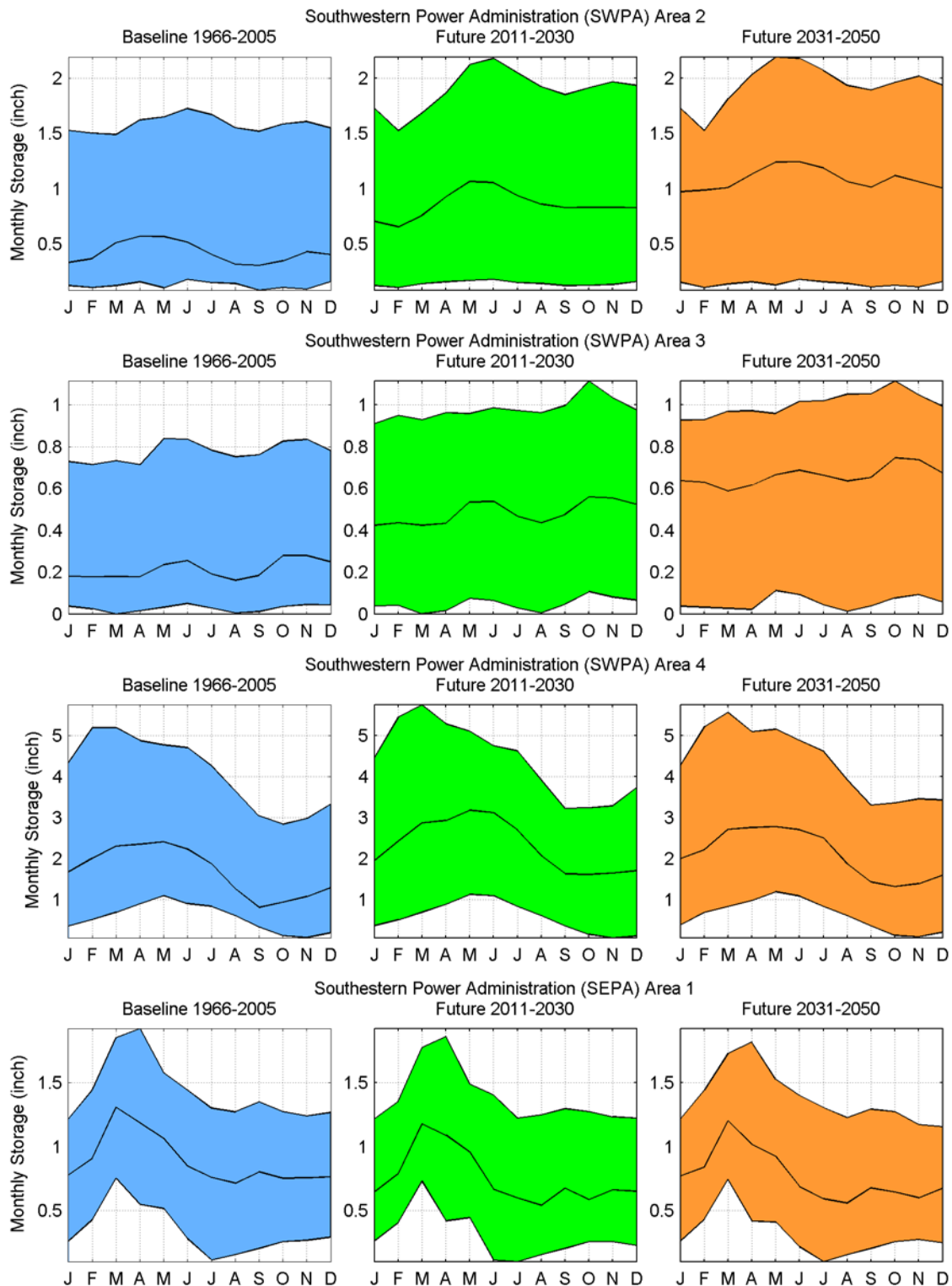
APPENDIX I. VARIABILITY OF MONTHLY WATERSHED STORAGE

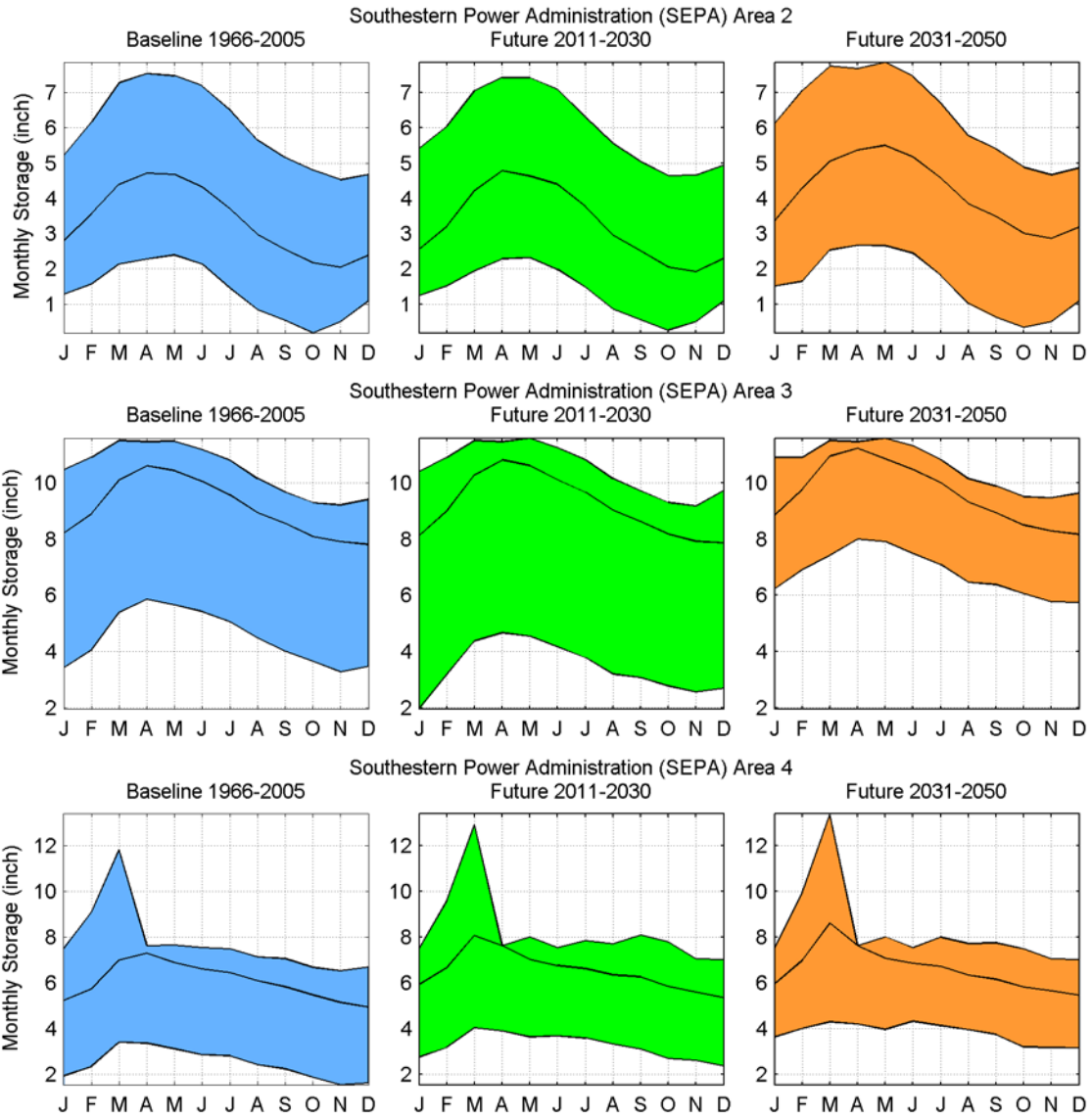
The monthly multi-model 10th, 50th, and 90th percentile watershed storage across ten climate models are showed for 1966–2005 baseline, 2011–2030 near-term future, and 2031–2050 midterm future periods for all PMA study areas.











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APPENDIX J. SUMMARY OF RESPONSE TO KEY REVIEW COMMENTS

In order to ensure the accuracy and quality of this study, an extensive external peer review was conducted in August 2015. Over 40 external reviewers, including federal and state power and water resource managers, climate and hydrologic researchers, and policy analysts, were invited to provide comments and feedback on this study. The main review comments, as well as the detailed responses provided by the research team, are summarized in this appendix. Statements in italics are the reviewer comments; they are followed by a description of revisions made to the final report. Where there is no response listed, it was deemed that no change was required.

Reviewer 1

1.1 Overall, I found this to be an excellent report. The analysis performed is very solid and the level of analytical detail appropriate for the purpose of the report. The report is well-written and organized. Chapter 2 (Assessment Approach) provides a very good overview of the methodological approach for assessment of climate change impacts on hydropower. All of the steps of the analytical process are covered in full detail, including possible shortcomings and potential improvements of the methodology. The results obtained for different regions (Chapters 3-6) are presented and discussed in a very clear way. Great discussion of potential climate change impacts and how they may affect different regions. Excellent list of references. My comments are mostly minor and editorial in nature.

- We appreciate these positive feedbacks. The comments and suggested editorial changes have been addressed in this revised report.

Reviewer 2

2.1 This is a very comprehensive assessment that integrates climate, surface hydrology modeling, and consideration of marketing region hydropower management. There are noted limitations of the assessment. Major direct limitations include the derivation of the hydropower generation based on a constrained regression analysis, lack of groundwater modeling, peak demand modeling. Although I (very much) appreciate the marketing aspect, my expertise and therefore my review focuses on the hydro-meteorological modeling and derivation of the hydropower generation.

2.2 Please clarify how RCP8.5 was chosen over the other existing RCPs? Also, in the limitation discussion and place for improvement, perhaps consider adding more RCPs. More integrated modeling, although not at this fine spatial scale, has demonstrated that this scenario looks more extreme in terms of temperature increase however policy implications on the technology reduced the stress on water compared to other median scenario like RCP4.5 (Hejazi et al., 2015).

- While we only selected one emission scenario in this study, it should be noted that this is not a controlling factor in the near-term and midterm future periods (i.e., the difference in GHG emission trajectories will only become significant after 2040s). As showed in the updated Appendix C, the median of 29 BCSD5-RCP8.5 ensemble members were in-fact very close to

the median of all BCSD5 members across four different emission scenario (RCPs 8.5, 6.0, 4.5, and 2.6), suggesting that the selection of RCP 8.5 will not result in a warm bias.

2.3 The overall derivation of hydropower generation based on a regression analysis and constraints based on storage range is conceptually sound and will give a good perspective of the hydropower generation potential. I do have reserves on the regression itself. It uses the previous 2 months precipitation and release. Over the Western US, snowmelt controlled basin would require a more extensive knowledge of the snowpack, i.e. more like an estimate of the previous 6 month precipitation, to compute the releases. Please could you clarify and or comment on that aspect? Another comment is on the constraint of the releases for staying in the storage range. There is no minimum release (can be zero) which is unrealistic. There should be a minimum flow release. Please could you also comment or clarify that constraint and the impact on the results. Finally, the change in seasonality of flow will affect the validity of the regression. There are large uncertainties with respect to the future monthly estimates of generation. The analysis is made at the seasonal scale and alleviates some of that uncertainty. Please could you discuss if a seasonal regression analysis, instead of monthly, could have led to less uncertainty or different results? (this might be an offline discussion).

- We appreciate these comments. Regarding snowpack, while it was not explicitly formulated in the multi-variate regression, the effects should be partially addressed by the natural runoff simulated by VIC. In other words, the snowpack will affect the amount of VIC-simulated runoff and hence will in-term affect the initial guess of regulated runoff release. Among the three types of variables in the regression formula, precipitation will provide inputs regarding the shorter-term hydrologic inputs, natural runoff will provide longer-term hydrologic response (such as snowpack), and regulated runoff release in the previous time step will provide information regarding the runoff storage in the watershed. As showed in Fig. 2.15, the WRES model can perform reasonably well in the snowmelt-dominated region such as BPA.

Regarding minimum release, while it was not formulated in the current WRES model, the total amount of minimum release should only be a smaller fraction of the total runoff release and hence may not seriously affect the magnitude of future hydropower projection. We will modify WRES to include the minimum release function for the future assessment.

Regarding the validity of regression in the future climate, it should be clarified that the purpose of these multivariate regression is to generate a first guess of regulated runoff release for hydropower generation based on the current energy-water system. How the energy-water system and water allocation decisions may evolve in the future were not considered in the current study. We are hoping to improve the representation of energy-water allocation decision in the future assessment to address some further operational questions and will be glad to test if the seasonal regression approach may work.

2.4 After quantile regression, the simulated CDF should match the observed CDF. However there seem to be difference in the figure. Could you clarify how the quantile mapping was done? Did each GCM got bias corrected using their own CDF?

- We apologize for the confusion. The difference between “Historic-Ensemble” and “Historic-Simulated” is caused by the temporal period. Note that the bias-correction was conducted using the entire 1966–2005 observed temperature and precipitation, not just the 1981–2005 period visualized in Fig. 2.9. So the different decadal and interannual variation in each climate model resulted in the difference in Fig. 2.9. In other words, if we changed the period

in Fig. 2.9 to 1966–2005, there should be negligible difference between “Historic-Ensemble” and “Historic-Simulated”. So, one main purpose of Fig. 2.9 is also to help us visualize the difference caused by climate model decadal and interannual variability during the baseline period.

2.5 I would suggest a summary diagram that clarifies the steps used for deriving the hydrologic simulations. It is presently unclear that after dynamical downscaling, the output is still bias corrected with respect to observation in order to be consistent with the observation dataset used for the calibration of the hydrology model.

- Thank you for this comment. In the revised report we try to better clarify that a 2-step downscaling (first dynamical to 18km and then statistical to 4km) is used in this study.

2.6 How was 4km resolution chosen? Most other assessments are at 1/8th degree although the University of Washington has increased it to 1/16th lately. Given the extensive downscaling required for that scale, it seems like 4km is an overkill. Only a certain number of improvements can happen between two assessments. If 4 km was a way to combine projects (small hydro related for example), it would help justifying the chosen spatial resolution.

- Our main consideration is the availability of high-quality gridded meteorological observation that can be used to drive and calibrate hydrologic simulation. In order to fully preserve the meteorological information from PRISM (without the additional smoothing of peak rainfall intensity during re-gridding process), we decided to set our hydrologic modeling grids to be in the exact resolution with PRISM, so the choice of 4km is not arbitrary. As discussed in Section 2 and also Oubeidillah et al. (2014), given the spatially inhomogeneous nature of rainfall, the peak rainfall intensities will unlikely be faithfully captured in a coarser resolution model, and hence it may lead to the underestimation of extreme runoff, which is one of the prime concerns of the possible future hydro-climate change.

2.7 Given that the Bureau of Reclamation is performing similar assessment on the hydrology, and they use operational seasonal water management models, I would suggest increasing the coordination with them for future assessment. In particular, qualitative comparisons are provided at the end of each regional section. In future assessment, Reclamation could run your downscaled assessment for a better estimate of uncertainties. Perhaps an element of clarification and/or line of improvement could be the following: Reclamation current assessments are from the water management perspective. ORNL perspective has been using Energy-centric regions, the PMAs. Is the energy management perspective currently captured with the regression relationships? Or how could it be better captured? What would be the difference from Reclamation's assessment?

- To increase the mutual understanding among various hydro-climate research activities led by Reclamation, USACE, PMAs, and other entities, the level of coordination has been largely increased in this second 9505 assessment, including a methodology workshop hosted by ORNL in September 2014 and several coordination meetings along various stages of the assessment. Recognizing the somewhat different objectives and existing model capacities, the focus has been to increase the understanding of methodological difference among various studies, and conduct comparatively analysis when situation allowed. Moving forward, it will be even more beneficial to increase the level of coordination as suggested by this comment. Further discussion on a more unified methodology will be of desire.

Reviewer 3

3.1 This report is well written. The methodology is clear and the organization is easy to follow. My general comments consider how the conclusions in this report relate to the SECURE Water Act Section 9503 Report that Reclamation is drafting.

3.2 In the abstract and conclusions the general statement is made that the most important climate change effect is likely to be the early snowmelt and change in runoff seasonality. Generally seasonality will have an impact on the timing of hydropower generation (i.e. potentially shifting generation, so it does not align with demands), but seasonal water availability is also an important concern and could be equally relevant.

- We appreciate the comment. We agree that the issue is not just runoff seasonality; seasonal water availability (i.e., a combination of change in both timing and magnitude) will be a more direct and important factor for hydropower generation. We only highlighted the change of runoff seasonality because it was more clearly shown in the simulated future hydro-climate projections. There are still higher uncertainties regarding how the magnitude of runoff may change in the future (mainly controlled by the amount of uncertain future precipitation).

3.3 Although this method does not take into account current operations, the expected impact on downstream hydropower production should be less given the regulation of the reservoir system. Although this study applies a regionalized approach without specific focus on particular reservoirs within a system it should be noted that the ability to store and release flows for downstream hydropower optimization may decrease the impact of climate change on certain hydropower facilities.

- We fully agree with this comment. As stated in the report, we noticed that the projected change of future hydropower generation is generally in a smaller magnitude than the projected change of future natural runoff, particularly for systems with larger storage capacity such as WAPA. This suggests that the increased future runoff variability could be lessened through reservoir operation.

3.4 Can a general conjecture be made regarding the how conservative the approach taken is compared to a site-specific or regional reservoir model? For instance, is one more conservative due to certain assumptions? Is this study focusing on a worst-case or conservative scenario, because operations are not taken into account?

- Our best guess is that the actual system may have the ability to optimize the energy-water allocation decisions so the projected variability of future site-specific hydropower generation could be in a smaller magnitude. Nevertheless, given the diverse site-specific constraints, such conjecture will likely involve a large uncertainty. For a particular reservoir of interest, further site-specific study will likely be needed to address various potential issues.

3.5 We have had a number of requests to create risk maps to highlight areas of climate change risk or projected impacts in the western U.S. Did you consider a "risk map" or indicator? This is not a suggestion to add a specific map or index, I just bring it up as it has been a frequent request for our report documentation.

- Thank you for the suggestion. As far we used the projected multi-model median runoff change (e.g., Fig. 7.2) as the general indicator to discuss the potential impacts on future water

availability. Depending a specific risk of concerns (e.g., drought or flood), further visualizations may be prepared to illustrate the potential risks in the future. We would be glad to collaborate with various stakeholders to prepare customized risk maps for the future assessment.

3.6 Until I made it to the specific results sections I did not realize that the analysis included a comparison to complete studies in each area. I think this is an import aspect that makes the analysis strong and relevant. It should be highlighted clearly in the methodology section.

- Thank you for the positive comment. This has been incorporated in the methodology section.

3.7 In section 2, Figures 2.2, 2.3, 2.4 (I believe) are not specifically referenced in the text. It is helpful to include a direct reference to all figures listed to help build context for their inclusion. As an aside to this comment, the figures included in this report are excellent.

- These figures have been referenced in the revised report.

3.8 The report notes that many of the reservoir-based models are also designed for short-term forecasting or mid-term resource planning (page 31, line 661-663). Do you see a greater importance for long-term reservoir operations planning models to understand hydropower impacts, such as CRSS in the Colorado River Basin?

- When available, the long-term reservoir operations planning models (such as CRSS) will be a very suitable choice to study the potential climate change impacts on water supply and hydropower generation. Nevertheless, as described in the report, such models were generally not applicable for various federal hydropower reservoirs and could have different model structures so that the inter-regional comparison will hard to be performed (i.e., hard to perform apple-to-apple comparison). It may be valuable to select and consistently adopt a long-term reservoir operation and planning model for the future assessment. Such efforts will require the intensive collaboration among various stakeholders.

3.9 There is no discussion regarding the reduced time/availability for off-peak power maintenance for hydropower facilities. Do you anticipate an impact to maintenance schedules and availability to work on infrastructure due to longer generation seasons or broader season demands?

- While we did not specifically analyze the potentially reduced time/availability for off-peak power maintenance for hydropower facilities, the results did suggest a high likelihood of earlier snowmelt (mainly due to increasing temperature) and hence the reduced off-peak time is possible in the projected future climate conditions.

3.10 On page 46, there is discussion regarding research frontiers. It should be noted that Reclamation completed a water demands study in Feb. 2015 that may be relevant to this discussion: <http://www.usbr.gov/watersmart/wcra/docs/irrigationdemand/WWCRAdemands.pdf>.

- We appreciate this information. The reference has been included in the revised report.

3.11 In your conclusions (page 161) you discuss the study as a "comprehensive assessment". We have gotten feedback that the assessments completed at a west-wide scale are "high-level" or "broad assessments", but aren't necessarily comprehensive due to the wide application of the method.

- Thank you for the comment. We have adjusted the wording in the conclusion section.

3.12 Appendix C could use some additional explanation as to why this comparison was generated. I think the comparison looks great, but the background context will be helpful to readers who are unfamiliar with the two datasets and the reason for comparison.

- We have modified Appendix C based on the suggestions from multiple reviewers.

Reviewer 4

4.1 The assessment is comprehensive and represents an informative study on the subject of federal PMAs and the effects of climate change on federal hydropower. I have several comments below, but in general the objectives of the technical assessment seem to have been met. A number of my detailed comments apply to more than one section of the report, especially with regards to certain phrases and grammatical errors. Below, I've noted reoccurrences in some instances, but not all. A thorough search for reoccurrences within the document would ensure quality.

- We appreciate these positive comments and feedback. The comments and suggested editorial changes have been addressed in this revised report.

4.2 Need to include an explanation somewhere in the document that provides more detail on how you chose the study areas. For instance, why do certain study areas in one PMA overlap with other PMA regions (e.g., WAPA-1 spills into BPA, SWPA-2 into WAPA, etc.)?

- We have now stated in Section 1.2 that the 18 assessment areas were determined jointly by river basin hydrology and power systems. A reference to the first 9505 assessment (Sale et al. 2012) has also been provided.

4.3 When presenting the results of your models in sections 3-7, be sure to keep the reader grounded in the significance of the data, and the uncertainty/variability underlying the data. I provide detailed comments below regarding data characterization. In general, be careful about over-generalizing trends. For instance, when boxplots almost entirely overlap, small differences in the median do not necessarily translate to a trend. Moreover, the uncertainty in the models and projections necessitate a conservative description, especially when data are close.

- We deeply appreciate the detailed review. All suggested changes have been incorporated in the revised report.

4.4 A quick note on hyphens- "use them when appropriate." As an example, the word "highlighted" does not need a hyphen, but "nonroutine" and "nonfederal" might.

- This has been modified in the revised report.

4.5 Recommend rephrasing the following sentence: "This can be explained by another feature of hydropower." From what I understand, fuel cost and generator dispatch were not actually incorporated into the climate change models. The sentence can be replaced with: "The absence of a related trend between temperature and generation will most likely be reinforced in practice when it comes to the utilization of hydropower to meet customer demand."

- We appreciate this comment. While we agree that peak energy demand (which is more related to temperature) will influence daily and hourly hydropower generation decisions, such temperature dependency is less noticed in the annual and seasonal scales (e.g., the multivariate regression formula used in the WRES hydropower projection model cannot be

improved by including the observed temperature). One possible reason is that, given the (relatively) lower cost of hydropower, the utilities would tend to fully utilize hydropower before switching to other fuel-based energy sources. Therefore, total annual and seasonal generation will follow water availability more closely (instead of demand). We would like to keep the original statement.

Reviewer 5

5.1 Overall I found the methods to be solid and the report to be detailed and well organized. Several important improvements since the last assessment have also been accomplished.

- We appreciate this positive feedback. The comments and suggested editorial changes have been addressed in this revised report.

Reviewer 6

6.1 The RegCM4 downscaling results would be of significant interest to the US research community. I may have missed it, but will this data be made available? Perhaps via CORDEX or some other ESGF venue? This data could be of use to the next US National Assessment report (US NCA4).

- We appreciate this positive feedback. Yes, we are making arrangements to make this data public in FY 2016.

Reviewer 7

7.1 Leaving aside the strengths and weaknesses of the Global Climate Models the report is based on, the downscaling method is appropriate and reasonable. The impact to hydroelectric generation is still based on a statistical correlation between runoff and generation, albeit a more educated lumped multivariate correlation. The use of the correlation to project impacts to generation is largely based on the assumption that the operation of reservoirs in a watershed will not change in the future. It has been Western's experience that reservoir operations have and will change over time for both climatic and non-climatic reasons.

- We fully agree with this comment. As stated in Section 2 (and various other sections), the current approach is based on the assumption that there is no significant change in the future installed capacity and operation. The issues of aging infrastructures and indirect effects may reduce the system's ability to mitigate runoff variability, thus increasing the difficulty of future operation. This will rely on more in-depth and site-specific studies that explore how adjusting current operating rules may help reduce the impact of climate variability in the future. Such issues are unlikely to be compressively evaluated at the national scale.

7.2 The report is well written and incorporates Western's input provided over the last year. Western hopes that ongoing efforts will model discrete streamflow points that can be incorporated into existing reservoir operations models.

- We appreciate this positive feedback. The research team will continue to work with PMAs to help provide useful information to help evaluate the potential risks for future hydropower marketing.

Reviewer 8

8.1 I reviewed sections 1-3, since I'm mostly familiar with the BPA regions. Overall, this is a great report and I look forward to having a copy when it's completed. Nice work. My comments are meant to help either clarify or address uncertainty in the assessment. Uncertainty can possibly manifest future work.

8.2 Although I'm not an editor, please be consistent with past or present tense throughout the document. "are" and "were" are frequently used within the same paragraph.

- This has been modified in the revised report.

8.3 Would be nice to see hydrologic model fits aggregated by PMA region as well as HUC8. This would allow it to be put into the perspective of the regional results.

- Given the scope of SWA, we focus on PMA region in this report. The HUC-based analysis and discussion can be referred to Naz et al. (2016).

8.4 Upon searching the document for "groundwater" returned only one hit from a reference regarding groundwater recharge. Given that VIC models do not explicitly address the groundwater components, it may be worth adding a short section addressing potential gains/losses associated with future groundwater demand.

- Following reviewers' suggestions, the hydrologic model limitations (including the missing ground water component) have been discussed in Section 2.4.

Reviewer 9

9.1 Very impressive analysis. The complexity of using GCMs/RCMS/VIC/and other data and models is immense. The methodology is clearly explained and the comparisons of model results to data are very informative.

9.2 Suggestion: clearly articulate models/methods that are being used based on other researchers' approaches vs. models/methods that were developed specifically for this analysis. It's not clear the extent to which the GCM to RCM to VIC approach is unique to this analysis or is based on methods that others have developed, peer reviewed and published. The WRES appears to have been developed specifically for this analysis, and it's not clear to what extent it has been validated in other venues or if this is developed as an analysis tool.

- Thank you for the suggestion. We have included a new reference Naz et al. (2016) that provides the technical basis for the RegCM4 and VIC simulations. The WRES model was developed specifically for this project. The applicability of WRES was reviewed and examined by various PMA staff as well as multiple technical reviewers.

9.3 A number of data sources and models are used, and it would be nice to have a high level summary early in the document; perhaps in Chapter 2. Including a summary of the types of parameters that vary with future climate would also be useful. For example, does the LAI change with each GCM scenario? Or is it representative of today's annual variations? What other inputs/assumptions (beside temperature and precipitation) are related to the overall climate scenario? Are there any of these assumptions/inputs that do not vary with climate scenario that should be considered for future analysis due to potential feedback effects that may be significant?

- We have inserted some further clarifications in relevant sections in the revised report.

9.4 The GCMs are designed to provide indicators of long-term average changes, but they do result in extreme annual values across the ensemble. Is there a way to use these extreme annual values to make any judgement about extremes of the future compared to today? Some discussion about this - limitations or potential methods of comparison would be helpful for those readers who are particularly concerned about the probability of increased frequency of extreme events resulting from a changing climate.

- We have included a new reference Naz et al. (2016) that provides further discussion into the projected hydro-climate extremes based on the same dataset used by this study.

Reviewer 10

10.1 Southwestern's marketing and contract mechanisms differ from the other PMA's. There are multiple occasions in the document where general statements are made about PMA structure that doesn't apply to Southwestern. Suggest removing general PMA statements and explaining each PMA's structure and operation in their respective section so as not to cause confusion and/or misinformation about each PMA.

- Even though there are marketing and contracting mechanism details that differ across PMAs, their overall mission is the same. We think that Section 1.2.2 is valuable for defining what a PMA is and introducing basic ideas about how they operate. The proposed alternative (defining and describing each PMA entirely separately) would be unnecessarily repetitive. We have addressed the specific suggestions in section 1.2.2 to make statements a bit more general and/or accurate.

10.2 The term "expected" is used several times in the document when referring to the climate change model results. Southwestern would prefer the use of "estimated" or "projected" which are the more common terms used in the document.

- This editorial change has been made in the revised report.

Reviewer 11

11.1 The report clearly represents a large amount of work on the part of the modeling and analysis teams. My main comments are not so much about the methodology used to downscale the GCM results and provide hydrologic and power generation projections, but with some of the interpretation and analysis as detailed in my comments below.

11.2 The report clearly has to distinguish between model spread and uncertainty. While the model spread (selection of 10 GCM models) captures some of the uncertainty in the climate projections, this is only one source of uncertainty in the modeling chain. This needs to be made more explicit.

- Thank you for the suggestion. We discussed in Section 7.1.3 that there is a need to further explore a broad range of hydroclimate modeling uncertainty which will hopefully improve the resource managers' understanding of future hydrologic projections and their implications.

11.3 The report needs to distinguish between findings that follow logically from its own analysis and the uncertainty about those findings. In a large number of cases the report hedges about results from its own analysis in a way that makes it sound as if the authors are not sure about their own modeling setup. For example, p.128 l.400-402: "The increasing annual hydropower generation trend is likely a direct consequence of the increasing annual precipitation and annual runoff simulated in this study" (another example can be found on p.161 l.36). The "likely" here is unnecessary. Given the modeling approach used here, the increase in generation is a direct result of the changes in precipitation and runoff. That is a different uncertainty than the one associated with whether the scenarios are the right one, whether the model parameters are optimal, etc. This may not seem important, but these results will ultimately inform decisions that are not solely technical in nature and it should be clear to these decision makers where the real uncertainties lie. There is no uncertainty that increasing the temperature in a hydrology model results in less snow, but there may be a lot of uncertainty about those temperatures, the parameters in the hydrology model, etcetera.

- We deeply appreciate the detailed review. All suggested editorial changes have been incorporated in the revised report.

11.4 The report is exceedingly repetitive in places. I assume that this may be by design, since people may only read the part that is directly relevant to their own region, so I have no commented further on this.

11.5 The comparisons with the Reclamation BCSD results (introduced in Section 7.1.2 and detailed in Appendix C) should be moved to the discussion of the individual regions or discussed in a separate section. Section 7 "Summary and Conclusions" is not the right place to introduce new analysis and this discussion is important to put the results in context.

- We have modified Appendix C and some related discussion based on suggestions from multiple reviewers.

11.6 The authors need to better motivate their choice of downscaling technique. If this was solely done for compatibility with the previous 9505 report then they need to state that clearly. If it was done for technical reasons, then they need to summarize them succinctly. As is, the potential advantages of using a dynamic downscaling technique are not well elaborated and the authors do not provide a clear motivation for what is a much more demanding technique. If all downscaling methods are created equal (I am not saying this), then the least expensive technique should be chosen since it allows for many more replications. For example, on p.165 l.113-117, the authors state that "While different downscaling approaches, climate models, and emission scenarios are selected in these two studies (and perhaps for all other concurrent hydroclimate studies), there is no implication of what method should be more superior. Each model, method, and technique has its own strengths and limitations, so the selection of a particular method for

climate projection should be driven by the user's specific needs." What are these specific needs in this case that require dynamic downscaling? Given that the hydropower generation effects are only evaluated at a seasonal time scale, what is the added advantage of this more expensive method. How did the advantages of dynamic downscaling manifest themselves in the results?

- In the light of reviewer's comments, we have revised the text in the relevant section to highlight the superiority of process based modeling over any other methodology for understanding regional climate change and its impact. In particular, we have noted that statistical downscaling cannot simulate the climate's response to rapid changes in external forcings. For instance, statistical extrapolation is particularly not useful in the case of snow hydrology as future changes in snow cover are known to be driven more by the increases in temperature and less by the variations in precipitation. Similarly, we note that by definition statistical bias correction is not capable of enhancing the spatial details of a climate change signal, calculated as a difference between the future and baseline integrations. Therefore, statistical bias correction without process-based dynamical downscaling will limit the ability to understand regional to local scale hydro climatic feedbacks resulting from fine-scale climate change as statistically bias corrected GCM data doesn't exhibit climate change signal more detailed than what is simulated by the parent GCM.

11.7 A brief section that explicitly compares the findings from this report with the first version of 9505 would be helpful.

- Thank you for the suggestion. The differences from the previous assessment have now been qualitatively discussed in the executive summary.

Reviewer 12

12.1 Excellent report. The report thoroughly describes methods and results for analyzing the impacts of climate change on federal hydroelectric project power output. Although hydroelectricity is outside my area of experience and expertise, I followed (almost) all of the narratives and figures. The results were well described and of clear importance for the country's energy portfolio. I applaud the authors for a report well written and study well run.

12.2 Executive Summary: At several points, the executive summary notes that this is the second 9505 study. Suggest summarizing key points from the first 9505 study and/or how this one differs from the first.

- Thank you for the suggestion. The differences from the previous assessment have now been qualitatively discussed in the executive summary.

12.3 Executive Summary/Chapter 1: Beyond reporting to Congress, what is the intended use of this study? Or how has the first 9505 study been used?

- In addition to providing the scientific basis for the report to Congress, this study was designed to explore the potential climate change effects on hydropower generation using a spatially consistent method, enabling policymakers to evaluate potential climate change impacts across the entire U.S. hydropower fleet. This effort is expected to promote better understanding of the sensitivity of hydropower plants to water availability and provides a basis for planning future actions that will enable adaptation to climate variability and change.

The hydro-climate projections have been used by other on-going hydropower research projects as possible scenarios affecting the deployment of future hydropower plants.

Reviewer 13

13.1 Is VIC run with a daily forcing data, only taking precip, wind, and Tmin/Tmax from the Downscaled data, or does it take SW and LW radiation, and Humidity from the dynamical downscaling as well? It would be nice to use the radiation and humidity data from the RegCM4 simulations so that the energy balance at the surface doesn't change arbitrarily due to changes in the temperature (e.g. SW shouldn't increase just because Tmax-Tmin does). Even if VIC is only given T, precip, and wind, it will calculate humidity and radiation internally using the MTCLIM algorithm.

- Given that the RegCM4-simulated temperature and precipitation need to be biased corrected before hydrologic modeling, we did not bring SW, LW, and humidity into VIC simulation (i.e., only RegCM4-simulated temperature, precipitation, and wind speed were used). Since both temperature and precipitation were adjusted, these variables must be updated to ensure the mass and energy balance in VIC. Further discussion regarding the RCM-VIC simulation can be found in Ashfaq et al. (2010).

13.2 Does RegCM4 use modified green house gases in it's radiative transfer code? The report mentioned at some points that the temperatures are a few degrees cooler in the dynamic downscaling than in the BCSD5 dataset, this would be consistent with not having modified greenhouse gases in RegCM4, and would be a cause for concern.

- Greenhouse gas forcings in RegCM4 baseline and future integrations match corresponding greenhouse gas forcings in the driving GCMs.

13.3 Comparisons to BCSD5 should show the BCSD5-RCP85 median, not the BCSD5 full ensemble median. It would also be useful to see a better indication of the spread in the BCSD5 data

- We have included another comparison in Appendix C showing only the BCSD5-RCP85 values. As indicated by this new comparison, the BCSD5-RCP85 median was similar to the full BCSD5 median. The result is expected since our focus is in near-term and midterm future periods (i.e., before 2050) and the difference among various emission scenarios are not significant.

13.4 The methods section states that the lower boundary is taken from the driving GCM, does this mean there is no land surface model in RegCM4? This will be detrimental to the representation of temperature change, particularly in the mountains where snowpack will substantially affect temperature changes.

- In the revised report, we have clarified that the atmospheric (moisture, temperature, zonal and meridional winds) and lower boundary conditions (sea surface temperature) from GCMs were used to drive the RegCM4 downscaling. Not just the land surface model in RegCM4 was utilized; the refined topography can help simulate the fine-scale land surface processes (e.g., snowpack) more credibly.

13.5 You should probably mention that there has been some work showing that the choice of hydrologic model, and even the calibration applied to a given climate model can substantially change the effect of climate change on runoff (e.g. Vano et al, Mendoza et al). Ah, I see this in the conclusions, but maybe it could be mentioned earlier as well.

- Thank you for the recommendation. The suggested references have been included in the revised report.

13.6 The potential variability in future climate seems like one of the most important messages, but I'm concerned that the downscaled data + VIC does not produce a reasonable source of interannual variability in current climate. In many regions, the "observed" runoff will have 2-5 years in a row of substantially above normal runoff, while the modeled data forced by ORNL downscaled data rarely has more than 1-2 years in a row in those same regions. This is particularly concerning because it means the GCMs and or RegCM4 are not providing the right multi-year variability, and multi-year droughts seem like one of the biggest potential problems, even for regions with substantial storage such as BPA and WAPA.

- We agree with this insightful observation. If our understanding is correct, this is a common and open research challenge among various GCMs. In other words, the current GCMs may not have the ability to reasonably simulate interannual and multi-year variabilities. The research team will continue to monitor the science development and hopefully such issue can be improved in the future GCMs.

13.7 Plots of the seasonal cycle of runoff in each PMA as well as the average seasonal cycle in the "observed" runoff would be useful to help evaluate how well the modelling chain is able to simulate the seasonal cycle.

- The difference between VIC simulated runoff and observation have been fully described in the calibration and validation section (2.4.3).

13.8 Given that the "observed" runoff is really derived from a combination of observations and statistical interpolation, it would be nice to see the modeled streamflow / runoff (aggregated over a basin) and the actual observed streamflow where available. This would provide a much better test of the hydrologic model.

- Given that the routed streamflow was not directly used in the hydropower simulation, the comparison between simulated (routed) and observed streamflow were not included in this report. The readers can refer to Oubeidillah et al. (2014) for further discussion and examples. The comparison of either streamflow or runoff for a common location can generally show similar results.

13.9 It would be nice to have a figure showing the RegCM4 model domain and topography

- This new Fig. 2.2 has been included in the revised report.

13.10 Consider changing appendices D and G to show the change signal in the future plots, as it is very difficult to see the change because the plots are overwhelmed by the seasonal cycle.

- Given that the change (future versus baseline) of temperature and evapotranspiration has been showed in each PMA section, we would like to keep appendices D and G in their current form. From appendices D to I, the readers will be able to see how these major hydro-climate variables may vary across various seasons and months. Such seasonality info is not available in other parts of the report.

13.11 Section 2.4.3, what is wrong with the 10% of stations which have no statistically significant correlation between VIC and SNOTEL SWE? Do these stations simply have bad data? Are the precip data wrong? Is the VIC model that bad in those regions? Are any of those stations in the various PMAs? If many of them are in the same area, can you confidently say anything about changes in runoff in that area? Is it even a fair test to test SWE simulated using observed precip? This test would be better if it were done using RegCM4 temperature and precip data when RegCM4 is forced using a reanalysis such as NARR or ERAi for the boundary conditions.

- In general, statistically significant correlation coefficients can be found for around 90% of the SNOTEL stations without spatial bias in a particular region (see Fig. 2.8). The poor performance of the rest 10% stations could be due to various station-specific reasons (e.g., not captured by the current elevation band) that can be explored in further details in a follow-up study. We are unclear why driving snow simulation by observed precipitation can be considered as an unfair test.

13.12 For the SWPA and SEPA, are tropical cyclones an important feature of precipitation in this region? Are they simulated by RegCM4? If these are missing from the analysis, is that a major problem?

- We agree with this observation. If our understanding is correct, this is another open research challenge among various GCM and downscaling studies. In other words, the current GCMs do not have the ability and spatial resolution to reasonably simulate tropical cyclones. The research team will continue to monitor the science development in CMIP6. Hopefully some higher resolution GCMs can start to capture tropical cyclones in the simulations.

13.13 In addition to figure 7.2, would it be possible to add a figure showing the difference between the 75th and 25th percentiles of change? This could even be used to normalize the median change signal as an indication of where change is more reliable. It is very difficult in fig 7.2 to see which areas are the same in the 25th and 75th percentile maps.

- Thank you for the suggestion. While we agree that the difference between the 75th and 25th percentiles of change can be informative, such figure may not be easily understandable to a wide variety of audience. We would like to keep Fig. 7.2 in its current form, but will produce the suggested figure in a subsequent, more scientific focused journal publication.

Reviewer 14

14.1 Nice comprehensive report. It's great for a technical audience. You might consider simplifying the executive summary further to make the report more accessible for general audiences.

- Thank you for the comment. We have revised the executive summary based on the suggestions from multiple reviewers.

14.2 The methods are generally sound. My only major concerns involve the downscaling implementation - see comments below. None of those major concerns preclude issuing these results as-is. I just think there needs to be better narrative about downscaling considerations,

rationale for your implementation, limitations of your implementation and how those limitations affect results interpretation.

- Thank you for the comment. We have revised various parts in Section 2.3 to better explain the rational and method of climate projection and regional downscaling.

Reviewer 15

15.1 The 132 federal hydropower figure cited throughout report subject to change given comments provided below.

- We appreciate this information. We have added the Lewiston powerplant in the assessment and removed the decommissioned Pilot Butte powerplant out from the assessment. The corresponding maps and figures have also been modified. The total number of federal hydropower plants remain 132.

15.2 How does this analysis account for new storage (i.e. reservoir) capacity?

- This study did not consider the expansion of new federal storage capacity in the future. With the current federal government attitude on future hydropower investment, we do not foresee a big increase on the federal portfolio. There could be more investment on the non-federal hydropower development. However, the current US market trend is mostly on smaller run-of-river projects that have nearly no manageable storage capacity.

15.3 How does this analysis account for efficiency?

- The change of generation efficiency is not considered in this study. The variability of efficiency is generally in a smaller scale than runoff variability. Therefore, it was intrinsically assumed a constant efficiency during the assessment.

15.4 How does this analysis account for climate change effects on hydropower ancillary services as well as the interplay between generation and ancillary services?

- The current PMA ancillary services were qualitatively discussed in power marketing sections (when applicable). However, climate change effects on hydropower ancillary services were not specifically discussed in this current study. It will require site-specific studies and cannot be covered in a national scale assessment.

15.5 Report states, "the focus on climate project is not to deterministically debate which models and/or downscaling techniques could be more scientifically superior." Is this the same approach adopted by the 9503 study?

- Yes, based on our understanding, it's a consistent approach with the SWA 9503 study.

15.6 Why are past years (2011-2014) considered Near Term? In other sections years 2011 and beyond are referred to as "future" realizations or periods (see p. 162) – does this make sense?

- We apologize for this confusion. The consideration of future period is in fact consistent with IPCC's experiment setup, in which all future GCM projections (under different emission scenarios) start from 2006. Year 2011–2014 is only a small portion of the entire near-term period (2011–2030) and should not affect the main focus of the analysis.

15.7 Installed capacity may be rather stationary, how does the model incorporate efficiency gains (e.g. turbine replacements, optimization systems)?

- As discussed, this study did not quantitatively consider capacity expansion, efficiency improvement, and also possible system degradation due aging infrastructures (i.e., assuming a stationary hydropower system). These issues are more plant-specific and have smaller direct relationships to climate change.

Reviewer 16

16.1 General Comment on entire report - Overall report speaks in a future tense specifically in regards to the accomplishment of the different studies. It reads as though studies have not been performed but will be in the future. Suggest reviewing report to correct tense issues.

- We appreciate the comments. This editorial error has been modified in the revised report.

Reviewer 17

17.1 The report is well written. I like the presentation of the results in a concise and easy to understand manner. The range of material presented covers the topic well and the consideration of variability in addition to trends is well done.

Reviewer 18

18.1 The calibration procedure of the WRES model is missing a validation step. It seems that all the data were used in the calibration and there was not a cross validation step similar to the procedure applied to the hydrologic modeling step. The concern is that the achieved goodness-of-fit might be due to overfitting.

- We have now clarified that the WRES model parameters were estimated by 1980–2008 precipitation, runoff, and generation records and then validated by 2009–2012 observation.

Reviewer 19

19.1 Overall a very well written and informative report. Thanks for the opportunity to provide comments.

Reviewer 20

20.1 Very good technical information, details and stats from what I was able to review.

20.2 Think the executive summary, from a reader's perspective, particularly a policymaker or staff, could be organized in a way that communicates the information more easily in formats (graphs/charts) that are less complex.

- Thank you for the comment. We have revised the executive summary based on the suggestions from multiple reviewers.

20.3 There are some great statistics on the system that start on this line and I am sure go throughout the report. Is there a way to do a "Key Facts" appendix that takes some of these stats and info and just puts them in a bulletized fashion in one place? Some of this may already be done in the DOE Hydro Markets report. But again I am just trying to think of things that policymakers and their staff would like to have as part of the report. If they want to base further legislation or policies off this report -- having easy access to the stats that are included throughout the body of the report would be very helpful to them and in general for other organizations. You may have this and I just haven't gotten to the end of the report.

- We appreciate this suggestion. Indeed, many key statistics of the current U.S. hydropower fleet has been prepared and can be obtained from the NHAAP – HMR2014 webpage (<http://nhaap.ornl.gov/HMR/2014>). We will also prepare some high-level 9505 fact sheets to help the users digest the information more easily.

Reviewer 21

21.1 Thanks for the opportunity to review the draft 9505 report. Overall, it's already in great shape. Well done. I've inserted quite a few comments and or track changes into the attached document – mostly minor editorial issues and some structural suggestions, which you can take or leave depending on the extent you find them useful. A few general things to think about as you move forward with revisions:

21.2 I like the probabilistic approach adopted in the report. I do think it is important to make clear that the probability distributions are conditional in nature – meaning they are contingent on the selected models and the use of RCP 8.5 (although over these time scales, the RCP doesn't matter that much) as well as the assumption of stationarity with respect to generation capacity, demands, prices, etc. You do point out this sensitivity in multiple places, but it might be useful to caveat this prominently in the initial summary and the conclusions. On a related note, despite the investment in generating distributions, much of the report focuses on the median result rather than what's happening at the tails. Generally, this makes sense – it's a useful way of concisely reporting a range of results. But it poses some potential issues with a multi-model ensemble, because it's not a random sample and not all of the models are "right" (in fact, probably none of them are). So if 9 of your 10 models point to an increase in runoff but 1 point to a decline, and the one is "correct", the median can be misleading. So is there an opportunity to say more about what's happening at the tails of the distributions, particularly with respect to generation. Ultimately, the issue is whether the focus on the median masks the risks at one end of the distribution and/or the opportunities at the other end.

- Thank you for the comments. While we used median to assist discussion in various places, the overall assessment was conducted in a more general fashion. When appropriate, the multi-model and multi-quantile information is provided to help visualize the variability in the

projected future meteorological, hydrologic, and hydropower projections (e.g., F.g 7.3). We have also caveated that the future hydro-climate projections involve large uncertainties. Therefore, these should not be considered as absolute prediction into the future. The ensembles distributions developed in this study serve as one most educated guess based on the current scientific understanding.

21.3 Sections 3-6 contain some common structures and text, which appear repetitive when one is reading the whole report. Such repetition can be useful if, for example, one anticipates that the audience will only read one of the PMA sections as opposed to all of them. However, it could be useful to consolidate some of the common caveats about the results in one section.

- Thank you for the suggestion. While we agree that Sections 3-6 are highly repetitive, this specific structure is by design, so that the PMA staff can use the information more easily. The common findings and caveats have been presented in Section 7.

21.4 On a related note as #2, descriptions of various figures in Sections 3-6 are often provided in the main body of the report while the figure captions are somewhat sparse. As noted in comments in the report, the captions should be enhanced so that the figure and caption can be interpreted as a stand-alone piece. This could enable the descriptions in the text to be removed in order to save space. However, they can also remain in place if that is preferred.

- Thank you for the suggestion. This is actually the preferred style as suggested by our editorial service. Therefore, we would like to keep the current format as is.

21.5 Might be worth commenting here that any probabilistic analysis is contingent on the data used in developing the probability distributions. Point being, one would get a different distribution, and therefore estimate of risk, if one used a broader range of models, or excluded models based on some set of performance criteria. Furthermore, risk assessment is sensitive to the assumption of socioeconomic stationarity regarding population growth, water demands, etc. So the distributions here do not necessarily capture the full range of uncertainty in temperature, rainfall, runoff, or hydropower generation.

- We agree with this comment. While we explored part of the uncertainty in this study, there exist other important sources of uncertainty (e.g., known and unknown unknowns) that should be considered for more informed future resource planning. We discussed the required future assessment needs in Section 7.2.

Reviewer 22

22.1 The report is very well prepared with an easy to follow organization that allows the readers to selectively dive into specific sections for details that they may be interested in. The methodologies are well accepted and comparable to state-of-the-art for development of the regional climate change scenarios and hydrologic simulations. The authors provided good discussions on limitations of their approaches and caveats of their results.

22.2 The report could include some more references to the literature. It's important for the readers to be able to find additional information should they want a more comprehensive assessment of methodologies and how the current results compare to previous studies.

- Thank you for the suggestion. Multiple references recommended by various reviewers have been included in the revised report.

22.3 Are the result of time series of precipitation and temperature shown in Fig. 4.2, 4.4, and similar ones for other regions based on bias-corrected RCM results or raw RCM results? It is not clear from the descriptions of the figures and discussions of results. If they are based on bias-corrected values, they clearly show that bias correction does not correct for biases in interannual variability. This may be important to point out and discuss the implications for hydrologic modeling and assessment of hydropower generation.

- The time series of precipitation and temperature shown in Figs. 4.2, 4.4 and other sections are based on bias-corrected RCM results. However, it should be noted that the purpose of bias correction is to adjust the monthly distribution of RCM simulated precipitation and temperature, not their interannual variability. Therefore, even after bias correction, the simulated VIC baseline runoff could still be different than the VIC runoff driven by observed precipitation and temperature, mainly due to their cumulative water budget difference due to different interannual variability. One main purpose of Fig. 2.10 and its related discussion is to illustrate this difference.

Reviewer 23

23.1 This language implies that the FCRPS has significant storage potential, but it depends on what it is being compared to. While this may be true compared to SEPA and SWAPA, compared to the Colorado and Missouri systems the FCRPS has significantly less storage. We sometimes refer to the FCRPS as a "storage limited system" - only being able to store 30% of runoff (versus 200% and 300% for the CO and MS systems). This is an important point that should probably be included in at least a FN as other areas in the report such as the indirect effects section note constraints due to a lack of water storage.

- We appreciate this comment. We agree that storage potential is a relative term and has clarified it in the revised report. We would also like to note that, even the storage potential of BPA, SWPA, and SEPA is relatively smaller than WAPA, the storage potential of federal hydropower plants is generally larger than the non-federal one. Therefore, the climate change induced runoff variability could have a more direct impact on non-federal hydropower plants.

Reviewer 24

24.1 Caption to Fig. ES.3: "The multimodel baseline (1966–2005) average is marked in a bold black vertical for comparison". Does this imply the models differ on historical periods? Why would that be?

- As discussed in the report, since annual hydropower generation is heavily influenced by water availability, it has a large interannual variability similar to precipitation and runoff. Therefore, the 1966–2005 generation values will be slightly different than the 1980–2012 generation mainly governed by water availability (i.e., wet/dry years).

Reviewer 25

25.1 We already spill a decent amount of water at Coulee in the spring months. If there is more water in those months I'm not sure we'd be able to really absorb that to maintain stable hydropower generation. Perhaps I'm missing something?

- We agree with this concern and have slightly adjusted the statement in the report to avoid possible confusion. While reservoir operation in the Columbia System has already been constrained (by various objectives), the system still has a relatively larger storage capacity (than non-federal ones) and should be able to help absorb part of the increased future runoff variability. Site-specific analysis will be required to further identify to what degree a particular reservoir will be impacted by the change of future hydrology.

Reviewer 26

26.1 I would think it isn't just that the Columbia River Projects have more storage but that the basic hydrology of the basins is different. The projects in the Cascade Mountains experience more winter runoff now and operations are geared for more rainfall driven flood control operations. More winter rain in the future isn't likely to change the shape of runoff much. The reservoirs in the Columbia River are for more snowmelt driven flood control and even with climate change will still have snowmelt influence from the norther part of the basin. This will influence the operations as projects like Grand Coulee will still need to draft during the winter to provide space for the spring freshet from snowmelt (although earlier). I would expect the future shape of runoff hydrograph for the Columbia to be flatter and more drawn out while the hydrograph for the Cascades is likely to be more the same shape just higher peak.

- We appreciate this insightful comment. Change has been made in this revised report to address the difference between the Cascade Mountains projects to the Columbia River projects.