

Hydropower Operations in the Colorado River Basin: Institutional Analysis of Opportunities and Constraints

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Executive Summary

The Colorado River Basin is facing an unprecedented drought. In ongoing drought management efforts, limited attention has been paid to hydropower generation. While some studies do exist on hydropower, they are quantitative in nature and focus on calculating the reduction in megawatts generated at dams in the Basin with declining water availability. These studies simplify the complex process of hydropower generation; water availability is but one factor that impacts hydropower generation. At a more fundamental level, *formal institutional arrangements*, that is, laws, policies, and rules create the framework within which dams are operated and hydropower is generated. This paper conducts a comparative institutional analysis of water, environment, and energy laws and policies and changes therein to understand the constraints and opportunities faced by hydropower generation in the Colorado River Basin. To tease out the nuances in how institutional arrangements affect dam operations and hydropower generation, the comparative analysis focuses on the two largest and strategically important dams in the Basin: Hoover and Glen Canyon. This paper uses Elinor Ostrom's Institutional Analysis and Development Framework to analyze laws and policies at three levels: constitutional-choice, collective-choice, and operational levels. Constitutional-choice level laws and policies apply to the entire Basin, whereas collective-choice level and operational level laws and policies are dam specific.

Hoover and Glen Canyon Dams face similar biophysical challenges by the virtue of their location in the same river basin. Yet, despite the similarity in the biophysical setting, the analysis in this study finds that the differences in the applicability of constitutional-choice level laws along with the differences in dam specific collective-choice and operational level institutional arrangements produce a distinct set of constraints for hydropower generation at Hoover and Glen Canyon Dams. Even without a drought, water and environmental laws at both the constitutional-choice and collective-choice levels as well as power contracts constrain hydropower generation and limit the flexibility with which Glen Canyon Dam can be operated. Water and environmental laws also impose specific water release requirements that, at times, require off-peak power generation at Glen Canyon Dam. On the other hand, even with a drought, Hoover Dam faces limited hydropower generation constraints and can operate flexibly. This is because constitutional-choice level laws and dam-specific collective-choice and operational level laws pose limited constraints for flexible daily operations at Hoover. The result is that Hoover Dam can generate hydropower at the same level as it did three decades ago and operate flexibly to provide ancillary services and peaking generation.

While water and environmental laws and policies pose constraints for hydropower generation, the analysis in this study further finds that specific historic provisions within energy-related institutional arrangements and recent changes within power contracts have maintained and even enhanced the value of hydropower to power customers. Historic institutional provisions ensure that hydropower is sold 'at cost' making this resource economically competitive with wholesale electricity market rates. Recent power contract modifications have resulted in the

amendment of an older resale prohibition clause to expand the flexibility available to power customers in using their capacity and/or energy allocation in RTOs, ISOs, and bulk power markets. This amendment has opened up an opportunity for customers, especially Hoover power customers, to use flexible generation and ancillary services in a market environment. In addition, the extension of power contract duration to the legally maximum term has enhanced the reliability and stability of this resource for customers. In the Colorado River Basin, despite the enduring economic responsibility of power customers—where laws require customers to pay for a large portion of construction and O&M costs whether or not they actually receive hydropower—the persistent threat of a drought-induced water shortage, and constraints imposed by water and environmental laws and policies, power customers continue to invest in this resource as energy-related institutional arrangements and power contract provisions protect the reasons why they value hydropower.

Lastly, the analysis in this study finds that the consequences of changes in hydropower generation for energy users, irrigators, and environmental programs in the Basin depend on how specific institutional arrangements tie electricity revenues to irrigation aid and environmental programs, and how the power contracts themselves are set up. Collective-choice level institutional arrangements create a higher level of financial dependency of irrigation aid and environmental programs on electricity revenues in the Upper Basin—the legal subdivision of Colorado River where Glen Canyon Dam is located—compared to the Lower Basin—the legal subdivision of Colorado River where Hoover Dam is located. Therefore, changes in hydropower generation or the way its revenue is collected and used will have far reaching detrimental consequences for the Upper Basin. Likewise, differences in the nature of power contracts for Glen Canyon and Hoover Dams also creates differences in the financial impact incurred by energy users when there is a reduction in hydropower generation. While this study identifies the *types* of impacts on resource users as a result of specific institutional arrangements, the calculation of *extent* of impact warrants further attention.

Hydropower in the United States is in a unique position today. The strategic importance of this resource for the nation's electricity sector is rapidly growing even as its contribution to overall electricity generation remains fairly small. This strategic importance, however, is built hydropower's ability to operate flexibly in order to support the integration of intermittent renewable generating sources and the expansion of electricity markets. As this study shows, such flexibility may not be available at certain plants not due to the lack of water availability but because of institutional constraints. Institutional arrangements may also require dam operators to first consider high priority water uses (such as irrigation or environmental needs), which in turn may limit the ability to generate hydropower when it is most valuable or useful. Engineering and quantitative models, such as production cost models, recognize policy constraints for hydropower operations but often inadequately capture or assume away such constraints in the models. A failure to account for policy constraints in these models runs the risk of inaccurate representation of the operational flexibility and capacity available at specific hydropower plants, which can result in over/underestimation of hydropower's ability to support the integration of variable renewable resources and address grid reliability concerns. Against this background, this paper and the analysis herein serves as an example of *how* we can systematically identify institutional constraints (and opportunities) that influence the flexibility in not only generating electricity at specific dams but also using this hydropower once it is generated.

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Abbreviations

BCPA	Boulder Canyon Project Act of 1928
CREDA	Colorado River Energy Distributors Association
CRB	Colorado River Basin
CRBPA 1968	Colorado Basin Project Act of 1968
CRSP	Colorado River Storage Project
CRSP 1956	Colorado River Storage Project Act of 1956
EIA	U.S. Energy Information Administration
EIS	Environmental Impact Statement
EPACT 1992	Energy Policy Act of 1992
EPACT 2005	Energy Policy Act of 2005
ESA	Endangered Species Act of 1973
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act of 1935
FPC	Federal Power Commission
FWPA	Federal Water Power Act of 1920
GAO	United States General Accounting Office
GCPA 1992	Grand Canyon Protection Act of 1992
GW	Gigawatt
HPPA 1984	Hoover Power Plant Act of 1984
HPPA 2011	Hoover Power Plant Act of 2011
IAD	Institutional Analysis and Development Framework
IOU	Investor-owned utility
IPP	Independent Power Producer
ISG 2001	Colorado River Interim Surplus Guidelines of 2001
ISO	Independent System Operator
LADWP	Los Angeles Department of Water and Power
LCR MSCP	Lower Colorado River Multi-Species Conservation Program
LROC 1970	Criteria for Coordinated Long Range Operation of Colorado River Reservoirs
LSE	Load Serving Entity
LTEMP	Long-Term Experimental and Management Plan
MW	Megawatt
MWh	Megawatt-hour
MWD	Metropolitan Water District of Southern California
NEPA	National Environmental Policy Act of 1969
NERC	North American Electric Reliability Corporation
PUHCA	Public Utility Holding Company Act of 1935
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
RoD	Record of Decision
RTO	Regional Transmission Organization
SLCA/IP	Salt Lake City Area Integrated Projects
UCRBC 1948	Upper Colorado River Basin Compact of 1948
USFWS	United States Fish and Wildlife Service
WAPA	Western Area Power Administration

1. Introduction

The Colorado River is one of the most legislated, litigated, and regulated rivers in the world. Every drop of this river is accounted for and prioritized to serve the water needs of over 40 million people, 4.5 million acres of farmland, and 22 federally recognized tribes, along with energy needs of over 4 million homes in the western U.S. (United States Bureau of Reclamation, 2012). Water availability to meet these multiple needs is however under serious threat as reservoirs on this river—built to make the desert bloom—are predicted to go dry by 2050 in the absence of effective drought management (Vano et al., 2014; Overpeck & Udall, 2010; Barnett & Pierce, 2008).

Given this imminent risk, public agencies at both the federal and state levels, resource users (both public and private), academics, policy scholars, and civil society representatives are working together to devise strategies to mitigate the impacts of the drought-induced water shortage in the Colorado River Basin. At the governmental level, for example, the Secretary of the Interior has commissioned studies to identify the consequences of an enduring drought on water supplies in the Basin and has signed various records of decisions to manage the dams in Colorado River Basin in the drought (see Department of Interior, 2007; United States Bureau of Reclamation, 2012). Within the academic and policy community the focus has been on identifying mechanisms to store and reallocate water within the existing legal framework, such as through banking and water markets (Culp et al., 2014; Colby et al., 2010; Bark et al., 2012; Rajagopalan et al. 2009; Glennon and Pearce, 2007). In all these efforts, however, not all water uses have received equal attention.

When laws and policies authorized the construction of dams in the Colorado River Basin since the early 1920s, they also ascribed priorities on how the water stored in the reservoirs could be used: water for agricultural and municipal needs received higher priority than hydropower generation, which was merely considered an incidental use. Consequently, agricultural and municipal water needs have dominated the research and policy agenda, while hydropower generation has received only limited attention.

Studies that do exist on hydropower in the Colorado River Basin are largely quantitative in nature and focus on calculating the percent reduction in megawatts generated under sustained drought conditions (Johnson et al., 2016; Christensen & Lettenmeier, 2007; Kopytovskiy et al., 2015). While drought-induced water shortage can impact hydropower generation as these studies go on to show, drought is not the only factor that influences electricity generation. In the Colorado River Basin, *formal institutional arrangements*—in this case water, environment, and energy laws and policies—create the framework within which dams are operated and hydropower is generated. These institutional arrangements—manifesting in the form of specific water delivery obligations, growth in the recognition of environmental water needs, rise in the grid penetration of renewable energy generation and the expansion of electricity markets—play

an important role in creating constraints (which are further exacerbated by the drought) as well as opportunities for hydropower generation in the Colorado River Basin.

Given this background, then, ***this paper aims to understand how water, environment, and energy laws and policies influence hydropower generation in the Colorado River Basin.*** The intent of this study is to conduct a legal and policy analysis of the historic and ongoing changes in key water, environment, and energy laws to understand how these laws create constraints and opportunities for hydropower generation.

Hydropower in the United States is at a unique juncture today. On the one hand, the growth in intermittent renewable generating sources, such as wind and solar, and expansion of electricity markets have increased the strategic importance of hydropower for the electricity sector (Key, 2013; Department of Energy, 2016a). On the other hand, dwindling water supplies, especially in the arid parts of Western U.S., have increased the competition for water among various water users which spells bad news for hydropower, just as the demand for this resource is growing (Sandia National Laboratories, 2011). Hydropower's ability to play a strategic role in the rapidly changing electricity sector as well as the ability of hydropower facilities to use water for electricity generation alongside other water users during a drought will depend on specific provisions contained in laws and policies. While most existing studies acknowledge this fact, very few studies actually analyze how laws and policies influence hydropower generation (Argonne National Laboratory, 2010; Sandia National Laboratories, 2011; Key, 2013; Clement, 2014). Consequently, the research presented in this paper comes at a time when we need a greater understanding of the role and influence of laws and policies on hydropower operations in order to grasp the challenges (or possibilities) that lie ahead for hydropower.

While this paper is explanatory in form, there are two underlying arguments driving this paper. First, while the entire Colorado River Basin is facing an unprecedented drought and as such the two legal sub-divisions in this Basin—Upper Basin and Lower Basin—face similar biophysical challenges, this paper argues that the actual constraints placed on dam operations for hydropower generation as well as the consequences of changes in power generation on resource users are markedly different in the two legal subdivisions of this Basin. The differences in constraints and impacts on users is a result of the differences in collective-choice level laws¹ and policies that govern dam operations in these two subdivisions. Second, this paper argues that despite the growing threat of a drought-induced water shortage and the constraints imposed by water and environmental laws and policies for hydropower operations, constitutional-choice level² and collective-choice level institutional arrangements pertaining to energy and power contracts contain provisions that ensure that hydropower continues to remain valuable to customers in the Basin.

¹The term 'collective-choice level' is explained in Section 1.1.1

² The term 'constitutional-choice level' is explained in Section 1.1.1.

With this background, the remainder of the paper is structured as follows. The approach and methodology, and limitations of this paper are discussed below in sections 1.1 and 1.2 respectively. Section 2 focuses on the institutional analysis of water, environment, and energy laws. This section is further subdivided into three sections. Sections 2.1 and 2.2 discuss the constitutional and collective-choice level laws and policies that govern dam operations, and energy marketing and allocation in the Basin. Section 2.3 analyzes how these higher-level institutional arrangements— i) influence the actual day-to-day dam operations, ii) impact the multiple reasons why customers value hydropower generated at the dams, and iii) create differences in the consequences of changing hydropower generation patterns for resource users in the Lower and Upper Basins respectively. Section 3 provides a summary of findings, conclusions, and direction for future work.

1.1 Approach and Methodology

1.1.1 Institutions and Comparative Institutional Analysis

Institutions are the humanly devised constraints that structure and guide human interactions in interdependent situations and define the opportunity set within which decisions can be made (Commons, 1924; Wandschneider, 1986; North, 1991; Schlager, 2016). Institutional economist John R Commons viewed institutional arrangements as the “working rules of going concerns” (Commons, 1924, p. 6). Working rules take various forms. They can be formal—laws, rules, property rights systems, decisions passed by courts, administrative agencies etc.—or informal—shared norms, customs, traditions, and codes of conduct (Commons, 1924; North, 1991). These rules guide and restrain behavior by dictating what individuals can and cannot do as it relates to a ‘going concern’, that is, the actual process of transacting/interacting with other human beings (Commons, 1924, p. 8). Further, the information that individuals obtain in any particular situation, the benefits they obtain or are excluded from, and how they reason about the situation are all affected by governing institutional arrangements (Ostrom, 2005).

Institutional arrangements play a fundamental role in the governance of natural resources. They determine “how people use, control, and allocate natural resources”, who can make decisions and how, the relationships between different uses of the resource, and ultimately who wins and who loses from changes in decisions over resource use and allocation (Bauer, 2009, p. 594; Bauer, 1998; Wandschneider, 1986).

In the context of the Colorado River, *formal* institutional arrangements, especially water rights, have been the topic of numerous books, academic and popular alike. The politics and conflicts over the distribution of water rights between different states, between the states and Native Tribes, between different consumptive water using sectors such as municipal and agricultural sector, and between consumptive uses and environmental needs, have been

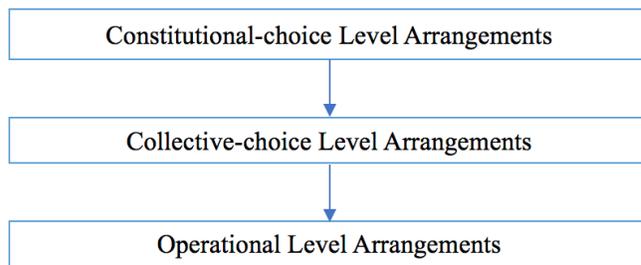
recounted in famous titles such as the Rivers of Empire (Worster, 1985), Cadillac Desert (Reisner, 1986), A River No More (Fradkin, 1995), Native Waters (McCool, 2007), Water and the West (Hundley, 2009), and more recently the Water Knife (Bacigalupi, 2015), Water is for Fighting Over (Fleck, 2016), and Where the Water Goes: Life and Death Along the Colorado River (Owen, 2017) to name a few.

Despite the scores of articles that have been published that examine the formal institutional arrangements—called Law of the River—on this river, there has been limited attention on hydropower generation, particularly, how institutional arrangements impact hydropower generation, how institutional arrangements shape the relationships between hydropower and other water uses, and how institutional arrangements affects the distribution of benefits and burdens from changing patterns of hydropower generation. This paper adds to the tome of literature on the Colorado River by examining how institutions create constraints and opportunities for hydropower operations in the Basin.

This paper recognizes that institutional arrangements are ‘nested’ such that rules affecting one situation are themselves crafted by individuals interacting at a higher level (Ostrom et al., 1994, p. 46; Ostrom, 2005). Institutional arrangements are thus not static structures but can change based on collective bargaining outcomes that occurs at these higher³ levels (Blomquist et al., 2004). From an analytical perspective, Kiser and Ostrom (1982) present three levels where institutions can be analyzed: operational, collective-choice, and constitutional-choice levels (see Fig. 1). Operational level institutions dictate day-to-day decision-making. Collective-choice level institutional arrangements exist at a higher level, and affect operational activities by determining who is eligible to influence operations, and specifying the rules that are to be used in framing and changing operational rules. Constitutional-choice level arrangements, in turn, determine who has the right to be a legitimate participant at the collective-choice level in framing the rules that apply to the operational level (Ostrom et al., 1994, p. 46). To study institutions is to understand how institutions change, and the three levels of analysis provide a framework for structuring research in this vein. Consequently, institutions that govern hydropower operations on the Colorado River will be studied longitudinally at these three levels.

³ Ostrom calls these ‘deeper’ levels

Figure 1 Three-Levels for Analyzing Institutional Arrangements



Note- Author's adaptation based on Ostrom 2005

In their 2004 agenda setting paper for institutional research in water resource management, Blomquist et al. (2004) suggest that the challenge for future in institutional research lies in going beyond the observation that institutions are important. It requires peering inside the “black box” of institutional processes and effects, “to provide explanations of how institutions matter,” how they prompt people to try to change management practice, how they ease or hinder those changes, how they shape management alternatives that water users/organizations consider and how they affect the resultant outcomes (Blomquist et al., 2004, p. 927). The authors suggest adopting a comparative perspective for analyzing institutions to allow isolating institutional effects from the myriad other factors that influence both decision-making and outcomes related to resource-use and management.

This paper therefore uses a comparative approach to study two dams in the Colorado Basin: Hoover and Glen Canyon. These two dams were selected for the study as they are the largest hydropower generators in the Basin, have the largest reservoirs (85% of the Basin's capacity), are connected such that Lake Powell (formed by Glen Canyon Dam) flows into Lake Mead (formed by Hoover Dam), and as such are strategically important as they connect the two legal subdivisions of the basin as each Dam is located in a separate part of the Basin: Hoover in the Lower Basin and Glen Canyon in the Upper Basin (Bunk, 2017; Jeka, 2016). Case selection is important for comparative analysis (Blomquist et al., 2004; Agrawal, 2002). Consequently, these two dams were selected as they face similar biophysical constraints by their virtue of location in the same Basin and are governed by the same constitutional-choice level institutional arrangements. These factors allow for a nuanced analysis of not only how institutions affect hydropower operations, but also how differences in collective-choice level arrangements in the two legal-subdivisions have different consequences for the hydropower operations at the two dams.

1.1.2 Methodology

This paper uses Ostrom's ‘Institutional Analysis and Development Framework’ (IAD) (Ostrom, 2005) as a lens to analyze and explain how institutional arrangements (exogenous

variables within the IAD) influence dam operations as well as power marketing, allocation, and resource use in the Colorado River Basin (action arenas in IAD) (see Appendix A for a very brief overview of the IAD). This paper also discusses the economic dependency created by institutional arrangements of water users (especially irrigators) and environmental programs on hydropower revenues, and in turn presents a preliminary discussion of the consequences of changes in hydropower operations on the water users and environmental programs.

The Colorado River Basin (alternatively referred to as CRB in this paper) is governed by a complex and evolving institutional structure, which includes federal and state-level laws, interstate compacts, intra-state agreements, numerous memorandums of agreement, administrative rules, court decisions and decrees, contracts with the United States and federal agencies, multiple international treaties/agreements, dam operating criteria, and records of decisions. Not all institutional arrangements influence how dams are operated or how hydropower generated at the dams is marketed, allocated and/or used by power customers.

Pertinent institutional arrangements for this study were identified using a two-step process. First, the latest edition of Colorado River Documents (2008)—the official compilation of key laws and policies (until 2007) used by the Bureau of Reclamation—was used as a primary guide to determine if a particular institutional arrangement influenced dam operations as well as power marketing, allocation, and resource use. Second, Bureau of Reclamation’s as well as Western Area Power Administration’s websites were then searched, and employees from these two agencies were interviewed to identify any additional institutional arrangements that govern dam operations or influence the power marketing and allocation process. A copy of the latest power contracts for Hoover and Glen Canyon—to be precise, Glen Canyon power contracts are termed SLCA/IP contracts—was also obtained from Western Area Power Administration. Once identified, these institutional arrangements were then analyzed using the IAD lens.

In addition to the legal and policy review, this study also involved a review of literature published by Federal agencies (Bureau of Reclamation and Western Area Power Administration), National Labs (notably National Renewable Energy Laboratory, Argonne National Laboratory, Oak Ridge National Laboratory, and Sandia National Laboratories), Colorado River Energy Distributors Association (CREDA) along with public presentations made by power customers and/or staff at Federal agencies, academic publications and books on topics pertinent to hydropower and water, environment and energy law and policy in the Colorado River Basin. This study also involved a review an analysis of wholesale electricity market data published by the U.S. Energy Information Administration (EIA). While the review of literature aimed to provide additional background information for the topics at hand, results from related studies, specific stakeholder viewpoints, and/or supporting evidence for findings, the review of wholesale electricity market data aided in the comparison of Hoover and SLCA/IP power rates against wholesale electricity market prices.

Lastly, semi-structured interviews were conducted with staff at Bureau of Reclamation, Western Area Power Administration and CREDA as well as utilities, electrical districts, and electrical cooperatives that receive an allocation of hydropower from Hoover or Glen Canyon Dams to understand—(a) the reasons why the customer valued hydropower from the Colorado River Basin, specifically Hoover and Glen Canyon Dams, (b) how (if at all) this value had changed over time, and (c) the risks, issues, and potential opportunities faced by hydropower from a legal and policy perspective. To capture the diversity in power customer perspectives, interviews were set up with customers both large—serving over 50,000 end users—and small—serving end users in the range of 60 to 50,000—that receive power from Hoover and Glen Canyon Dams and belong to/serve six of the seven Basin States, i.e. California, Nevada, Arizona, Colorado, New Mexico, Wyoming⁴⁵. Of the customers that were interviewed, two interviewees—one large and one small—received an allocation of both Hoover and Glen Canyon power, which provided an additional comparative perspective on the constraints (and opportunities) for hydropower generation at the two dams. For confidentiality reasons, the names of staff members at the Bureau of Reclamation, Western Area Power Administration and CREDA along with names of Hoover and Glen Canyon customers (i.e. utilities, electrical districts etc.) and staff members that volunteered to serve as interviewees will not be included in this paper. Instead, general identifiers such as ‘staff at Reclamation’ will be used for the federal agencies and ‘staff at utility in CA/AZ/NV/NM/CO/WY’ will be used for power customers.

1.1 Limitations

Although some water, environmental, and energy laws analyzed in this study are applicable to hydropower projects in other river basins, a large number of project-specific water laws discussed in this study are unique to the Colorado River Basin. Moreover, the overarching institutional framework that emerges from the combination of the three sets of laws is also unique to the Colorado River Basin. Consequently, it is difficult to generalize the findings and conclusions of this study. The differences in the history, biophysical setting, and policy setting for each hydropower project in the United States creates a specific set of constraints and opportunities for each project; it is rare for two dams to have the same overarching governance framework. In this context, then, we can view this study as an example of *how* we might conduct institutional analysis for the different hydropower projects in the country as opposed to a study

⁴ Interview requests were sent to customers in Utah. However, either no responses were received or the customer suggested that the author contact CREDA.

⁵ All the customers that were interviewed were ‘public power’ agencies, that is, they were electrical and/or irrigation districts, municipal power utilities, electrical cooperatives etc. Native Tribes receive an allocation of Hoover and Glen Canyon power; however, approvals and permissions are required from the Institutional Review Board as well as each Tribe before the Tribe can be interviewed. As the approval process takes a long time, Tribes were not interviewed as part of this study.

that sheds light on the general opportunities and constraints for hydropower generation in the country.

Given the research topic at hand, this study adopted an approach where institutional arrangements were discussed in a chronological order with a narrow focus on analyzing how a particular law/policy/record of decision affects dam operations or power marketing, allocation, or resource use. Institutional arrangements are not created in a vacuum, however. Each law/policy/record of decision has a history and is influenced by external political and economic factors. Likewise, institutional arrangements themselves are not neutral documents; information represented in these documents or the wording of certain laws can and have been a source of conflict. This study includes a limited discussion of the political and economic history of institutional creation and change⁶ as well as conflicts, as this discussion would have taken the focus away from the specific research topic at hand. However, it must be noted that this study is part of a broader dissertation project that will explore the history of institutional creation and change as well as conflicts that have emerged as a result of having to manage hydropower operations at the intersection of water, energy, environmental laws and policies.

Finally, in Section 2.3, there two limitations pertaining to data and the analysis of impacts of changes in hydropower generation on resource users. The data limitation is two-fold. One, the data presented on energy generation at Hoover and Glen Canyon Dams was procured through the Bureau of Reclamation in May 2017; however, at that time, data were not available for the same years for both dams. Data for Hoover were available at a longer time-scale than Glen Canyon and therefore Figures 5–8 do not show the same time-scale for generation. Two, for Figure 9, i.e. the chart showing rates for Hoover and SLCA/IP hydropower compared to wholesale electricity market prices at Palo Verde and Southern California (SP-15) hubs, the composite rates for Hoover power were not publicly available for a part of the time-period under consideration. Consequently, for this part, i.e. where Hoover rates were publicly unavailable, interviews and public presentation made by power customers were used to identify the general rate range. Additionally, there was a data discrepancy in that the Hoover and SLCA/IP composite rates were available at an annual time-step, whereas Palo Verde and SP-15 prices were reported on approximately daily time-steps. The prices at Palo Verde and SP-15 were also not consistently reported for the same days. As Figure 9 was created for illustrative purposes only, the idea was to show the general trends in changes in wholesale electricity market prices. Consequently, the daily weighted average price per MWh at Palo Verde and SP-15 was averaged on an annual time-step. The annual averages of daily weighted average price per MWh do not reflect the day-to-day fluctuations in daily weighted average prices. For example, during the 2001 California

⁶ Some of this history, especially with respect to water law, has been discussed in Reisner (1986), Ingram (1990), Hundley (2009). This study provides some background information with respect to energy related laws and policies as this history is less well known to individuals and scholars outside the sector.

energy crisis, the daily weighted average price for electricity could fluctuate from \$530/MWh one day to \$360/MWh the next day at SP-15.

With respect to analysis of impacts of changes in hydropower generation for resource users, i.e. Question 3 under Section 2.3, the analysis is geared towards identifying the *types* of impacts that will be faced by energy users, irrigators and the environmental programs due to the specific ways that hydropower generation or its revenues are tied to each resource user group or program. The *extent* of impact, such as impacts in actual dollar values, however, has not been calculated. This is because assessing the *extent* of impact, involves the consideration of far more variables than those discussed in this paper, and these variables are anything but static. For example, the extent of impact on energy users from reduction of hydropower generation will depend on a host of factors including the share of hydropower allocation in the user's overall electricity portfolio, changes in the user's electricity load profile, the user's ability (financial and technical) to access and purchase electricity from electricity markets to make up for the shortfall in generation etc. Estimating the extent of the impact of changes in hydropower generation on resource users, therefore, goes beyond the scope of this study as it requires additional data (some of which is confidential in nature), computational resources, and technical expertise that the author does not possess; however, it merits further attention.

2. Institutional Analysis of Water, Environment, and Energy Laws

This section presents an overview and discussion of how water, environment, and energy laws and policies influence dam operations as well as power marketing, allocation, and resource use by customers in the CRB. This section is divided in three subsections. The first subsection discusses constitutional-choice level institutional arrangements that apply to the entire CRB and create the framework that dictates who can receive water and power from the dams in the Basin and who can formulate rules and policies at the collective-choice and operational levels. This subsection also presents a brief overview of the major federal laws and policies pertaining to electricity and discusses how these laws and policies apply to hydropower in the CRB.

The second subsection focuses on the collective-choice level institutional arrangements that apply to specific projects. Collective-choice level institutional arrangements are arguably the most important set of arrangements in the context of this study as they differentiate the constraints for dam operations, the specific provisions of power contracts, and the level of economic dependency of agricultural and environmental water sectors on hydropower generation between Hoover and Glen Canyon Dams. The third subsection synthesizes the analysis at the constitutional-choice and collective-choice levels at the level of day-to-day dam operations to make explicit how differences in institutional arrangements influence- a) hydropower operations and, b) the multiple reasons why customers value hydropower, and c) the potential consequences (a preliminary assessment) of changes in hydropower generation.

2.1 Constitutional-choice Level

Laws and policies governing water allocation and dam operations in the CRB have increased both in number and complexity over time; yet, under this complexity, there is an identifiable foundation of laws that determines- i) who has a right to the water in the Basin, ii) who can participate in crafting new laws/rules/policies for managing the water (and associated dam operations) in the Basin, iii) the purposes and manner in which water in the Basin can be used, iv) who can generate and market electricity from reclamation facilities, and v) the fundamental principles of allocating and marketing power to prospective customers. These foundational set of laws apply to the entire Basin and form the constitutional-choice level rules within which actors create lower levels of institutional arrangements, i.e. collective-choice rules and operational rules to manage dam operations in the Basin.

This section consists of three parts each discussing water, environment, and energy laws and policies that govern dam operations and power marketing and allocation in the Basin. The three sets of laws are equally important though they pose different governance challenges or operational constraints for Hoover and Glen Canyon Dams. We will discuss these challenges and constraints in turn in the sections on collective-choice level and operational level.

2.1.1 Water Laws and Policies

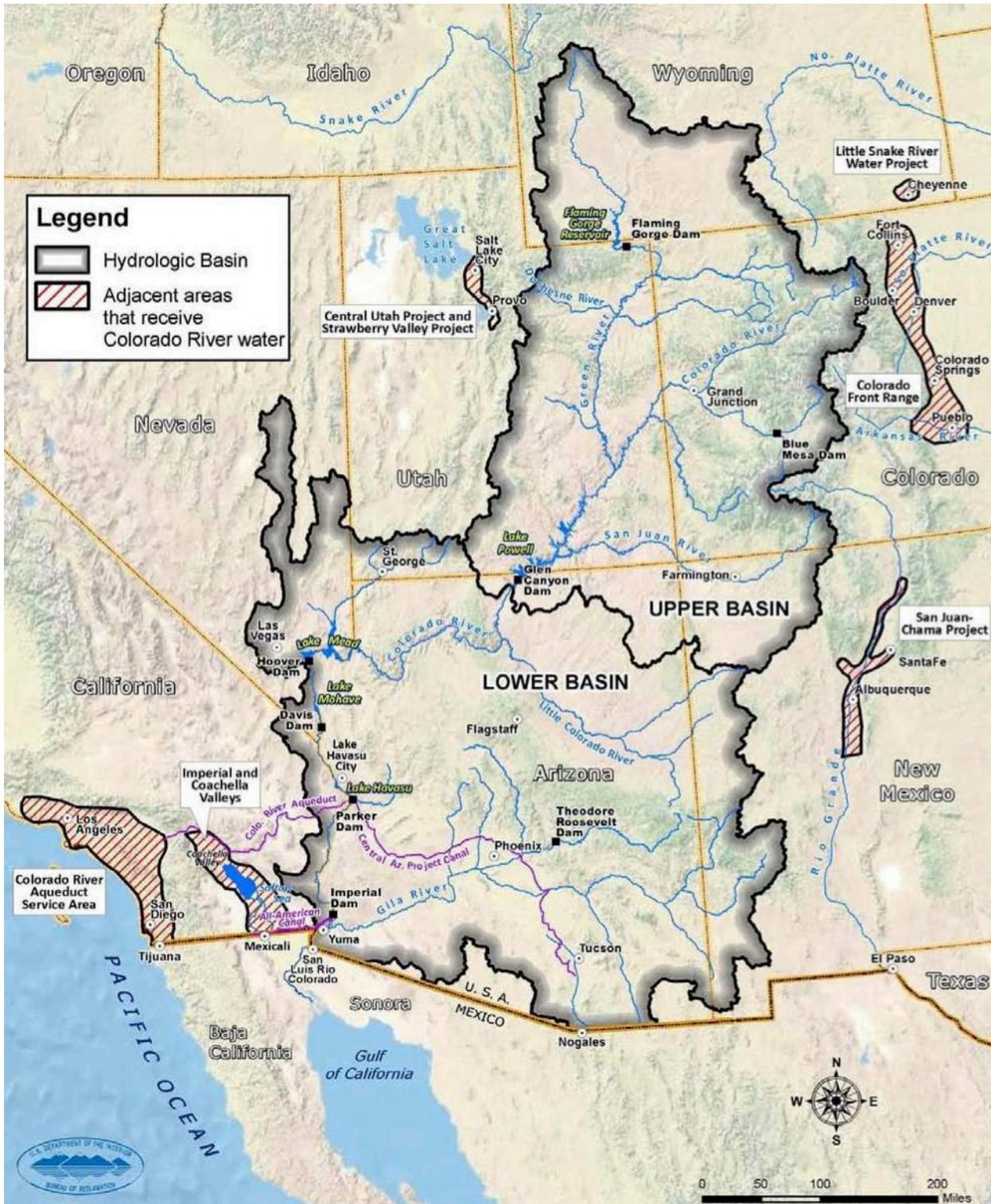
To trace the earliest constitutional-choice level rule, we have to go back in time over a century to 1902 when Congress passed the Reclamation Act. At the time water resources in western part of United States were particularly unseemly, water either appeared in the wrong place or at the wrong time (Hess, 1996, p. 35). This was bad news for agriculture that needed predictable supply of water. The proponents of the Reclamation Act believed that ‘reclamation’ projects⁷, would encourage Western settlement by creating secure water supplies and in turn allow ‘homemaking’ whereby Americans could build homes on family farms (United States Bureau of Reclamation [hereafter Reclamation], 2016). With irrigation as its primary focus, the Reclamation Act created the U.S. Reclamation Service (renamed Bureau of Reclamation in 1923) and authorized this agency to build dams and federal irrigation projects to primarily supply water for agricultural development. This act, therefore, set the main priority of water infrastructure development and use in the West: irrigated agriculture.

Although the Reclamation Act paved the way for building dams in the Colorado River Basin, such construction could not proceed unless water in the Basin was first allocated within the seven states—California, Arizona, Nevada, New Mexico, Colorado, Utah, Wyoming—that depended on this river. To this end, the federal government and the seven states signed the Colorado River Compact in 1922—foundation of the ‘Law of the River’—to equitably divide water in the Basin and “to establish the relative importance of different beneficial uses of water”

⁷ In the jargon of the day, irrigation projects were known as reclamation projects (Reclamation, 2016)

(Article I, Colorado River Compact 1922). To this end, the 1922 Compact arbitrarily divided the Basin into two parts—Upper Basin and Lower Basin—and allocated 7.5 million acre-feet water to each of the two sub-basins, and created a provision wherein surplus water could be allocated to Mexico (Article III, Colorado River Compact 1922) (see Fig. 2 for the division of the two sub-basins). Per the Compact, use and consumption of water for agricultural and domestic purposes was deemed more important than electricity generation, which in turn had priority over navigation (Article IV, Colorado River Compact 1922). This preference ordering reiterated the priorities of the 1902 Reclamation Act and additionally clarified the preeminence of electricity generation over navigation. In addition, Article III (d) of the Compact required the Upper Basin states to ensure that the flow of the river at Lee Ferry did not deplete below an aggregate of 7.5 million acre-feet over a ten-year consecutive period. This was arguably the first institutional provision that differentiated the constraints of operating Glen Canyon and Hoover Dams. Even in case of a water shortage for example, water had to be released from Glen Canyon Dam to meet the Compact obligations without a consideration for the Upper Basin's consumptive water needs or hydropower generation, effectively placing the burden of bearing climate-related impacts on the Upper Basin States.

Figure 2 Map of the Colorado River Basin



Source-Colorado River District, 2016

Whereas the 1922 Compact defined the state-level claimants to water and priority of water uses in the Basin, it only alluded to Mexico's stake to the water. The Mexican Water Treaty of 1944 assured delivery of 1.5 million acre-feet of water to Mexico from the Colorado River (Section a, Article III), and thereby made the country a legitimate participant in decision-making related to the river through the International Boundary and Water Commission.

2.1.2 Environmental Laws and Policies

A brief recap of the constitutional level water laws indicates that environmental water needs and interests were not recognized in the foundational institutions that allocated water in the Colorado River. In the 1960s, environmental groups opposed construction of dams in the Grand Canyon on the grounds that these dams would cause detrimental impacts for downstream ecosystems⁸. This led to the recognition of environmental and recreational interests in subsequent collective-choice level legislations passed by the Upper Basin States; however, meaningful consideration of environmental interests did not occur until later in that decade when the National Environmental Policy Act (NEPA) was signed into law in 1970⁹ followed by the Endangered Species Act (ESA) in 1973¹⁰.

NEPA helps to ensure that federal decision-makers and the public are informed regarding the potential impacts of proposed federal actions. Every time Reclamation proposes a change in operations in the river/proposes alternative dam operation regimes, it is required to prepare Environmental Impact Statements (EIS), which leads to adoption of Records of Decisions that affect operational level decisions in Basin. Likewise, ESA requires federal agencies (in this case Reclamation) to conserve endangered and threatened species (Section 7 (a) 1), ensure that the discretionary actions of the agency do not jeopardize the continued existence of listed or threatened species or adversely modify designated critical habitat (Section 7 (a) 2), and prohibit the unauthorized take of individual members of listed species (Section 9).

These two federal legislations have been the cornerstone of safeguarding environmental water needs/interests in the CRB. Collective-choice level decisions that are made by the seven

⁸ Sierra Club, for example, opposed the initial infrastructure development plans laid out under the Colorado River Storage Project Act as the plan called for the construction of a series of dams on the Colorado including those at Echo Park and Split Mountain in Dinosaur National Monument, which would have had detrimental environmental consequences (Brower, 1997). The environmental groups, however, gave a reluctant nod for the construction of Glen Canyon Dam on the condition that the other dams on the river would not be built.

⁹ Although NEPA was signed into law on the January 1 1970, it was enacted in 1969 and thus NEPA is cited as the National Environmental Protection Act of 1969.

¹⁰ It must be noted that there are other federal environmental laws—particularly Migratory Bird Treaty Act, 1918, Migratory Bird Conservation Act, 1929, Fish and Wildlife Coordination Act, 1934, Bald and Golden Eagle Protection Act, 1940, Clean Air Act, 1963, National Wildlife Refuge System Administration Act, 1966, Wild and Scenic Rivers Act, 1968, Clean Water Act, 1972—that also apply to federal actions. However, in the case of dam operations in the Colorado River Basin, these laws kick-in while conducting an environmental assessment under NEPA. Therefore, NEPA sets the broad guidelines for ensuring inclusion of environmental conservations while making any changes to dam operations.

basin states and government agencies have to adhere to the provisions of these two laws. Although environmental water needs are non-consumptive, i.e. water released for environmental needs do not take away the amount of water that can be used by say agricultural or municipal sectors, they do affect how and when water can be released. Over the years, dam operations have been modified to account for the requirements of these NEPA and ESA, especially in the case of Glen Canyon Dam as will be discussed in the subsequent sections.

2.1.3 Energy Laws and Policies

The electricity system in the United States has evolved over the last century from a patchwork of small, independent systems to a highly complex and interconnected system serving over 150 million customers (Flores-Espino et al., 2016). Electricity that is generated at dams in the CRB ultimately passes through wires that are part of this interconnected grid. While constitutional-choice level water and environmental laws and policies can be understood in isolation, that is, as they apply to the CRB, this is not the case with constitutional-choice level laws and policies pertaining to energy due to the interconnected nature of the electricity grid. Federal laws and policies have transformed the electricity sector with consequences for the role of hydropower in this transformed sector generally as well as the operations of federal power marketing agencies specifically.

Against this background, this section begins with a discussion of the major federal laws and policies pertaining to the electricity sector that have had an impact on the structure of the sector in subsection 2.1.3.1. This section focuses only on federal laws and policies as opposed to *both* federal and state level laws and policies because hydropower generation in the CRB, or more precisely operations of the federal power marketing administration (Western Area Power Administration) that allocates and markets hydropower from Hoover and Glen Canyon Dams, is governed to a limited extent by federal laws and policies pertaining to electricity. State level laws and policies do not directly impact the operations of federal power marketing administrations.

After a discussion of the major federal laws and policies pertaining to the electricity sector, this section focuses on the specific constitutional-choice level energy laws and policies that apply to the CRB along with a brief discussion of the applicability of major federal energy laws and policies to the operations of Western Area Power Administration in subsection 2.1.3.2. Constitutional-choice level energy laws and policies dictate— a) who can generate and market electricity from reclamation facilities, and b) the fundamental principles of allocating and marketing power to prospective customers. Over time these constitutional-choice level laws have changed, in turn reflecting a change in the authority to generate and market power as well as specific power allocation and marketing principles. Subsection 2.1.3.2 traces the changes in energy related laws and policies over time and as with water law begins at the beginning, i.e. with the passage of Reclamation Act of 1902.

2.1.3.1 Major Federal Laws and Policies Pertaining to the Electricity Sector

The U.S. electric power industry, termed as the “last major regulated energy industry in the United States” by the U.S. Energy Information Administration (2000, p. ix), has seen a fundamental shift in structure over the last few decades. Where power generation was once dominated by vertically integrated investor-owned utilities (IOUs) that owned most of the generation capacity, transmission, and distribution facilities, the electric power industry has now seen a rapid rise in many new companies that produce and market wholesale power. The nation’s transmission system is also being reorganized from a balkanized system with numerous transmission system operators to one where only a few organizations operate the system. This shift in structure has been brought about by a host of laws and policies at the federal and state levels that have evolved over the course of the last century. This section traces the evolution of the major federal laws and policies that have influenced the structure of the electric power industry and begins in the early 1900s, the period that marked the first structural realignment in the history of the industry.

In the early 1900s, states regulated nearly all of the activities of electric utilities and the utility industry often relied on holding companies. Holding companies represented a financial structure wherein a parent company held financial stocks and bonds of subsidiary utilities in order to improve financial performance and capitalize on economies of scale (EIA, 2017a). As efficiency increased in electricity generation, utilities began to expand their service territories (EIA, 1993). As these utilities were controlled by holding companies that engaged in interstate commerce, it was difficult for State public utility commissions to regulate these utilities due to Federal preemption (EIA, 1993). A 1927 Supreme Court Case¹¹ further complicated matters as it held that State regulation of wholesale power sales by a utility in one State to a utility in a neighboring State was precluded by the commerce clause of the United States Constitution. The lack of jurisdiction to govern interstate transactions coupled with a severe deficit in trained and experienced personnel and financial resources left a large portion of utility transactions unregulated.

By 1930, 90 percent of all operating companies were controlled by 19 holding companies (EIA, 1993, p. 6). This highly concentrated nature of the public utility business along with the collapse of the many utility empires and poor performance of the operating companies during the Great Depression ultimately resulted in demands for their regulation (EIA, 1993). While it became apparent that the Federal Government would need to step in to address the issue, no Federal agency existed at the time to regulate these companies. Although Congress had passed the Federal Water Power Act in 1920 (hereafter FWPA) that created the Federal Power Commission (FPC) (Section 1), this commission was only entrusted with the responsibility to provide federal oversight over hydropower development over navigable waterways in the country (Section 4 (e)). To address the regulatory gap, Congress enacted the Public Utility

¹¹ Public Util. Comm’n of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927)

Holding Company Act in 1935 (hereafter PUHCA). Title I of PUHCA created the Securities and Exchange Commission to monitor and regulate the activities of holding companies. Title II of PUCHA amended the Federal Water Power Act of 1920. As part of the amendment the FWPA of 1920 was renamed to Federal Power Act (FPA) and the original provisions of FWPA became Part I of FPA (PUHCA Section 212). In addition, the FPA included two additional parts: Part II relating to regulation of electrical utility companies engaged in interstate commerce and Part III dealing with licensing and administrative matters (PUHCA Section 213). Part II significantly expanded FPC’s authority to regulate utilities (and their facilities¹²) involved in interstate commerce and ensure that corresponding rates were “reasonable, nondiscriminatory, and just to the customer” (PUHCA Section 213)¹³. The 1935 Act shaped the electric power industry for over half a century by creating the legal framework within which the industry was allowed to develop.

For almost three decades after the passage of PUHCA the electricity industry saw a steady growth in electricity demand (Isser, 2015). Utilities were able to meet this growth in demand through technological advances—primarily increase in thermal efficiency of fossil fuel steam generation¹⁴—at declining prices (Isser, 2015; EIA, 2000). However, a series of events occurred between the late 1960s and the late 1970s that contributed to the reversal in the growth and well-being of the industry. The Northeast Blackout of 1965 raised concerns over electricity reliability, the passage of environmental laws including the Clean Air Act Amendments in 1970 and 1977 posed pressure on utilities to reduce polluting emissions, the oil embargo imposed by Nations of the Organization of Petroleum Exporting Countries from October 1973 to March 1974 heightened awareness of United States’ dependency on foreign oil, the Three Mile Island meltdown in 1979 exacerbated the challenges and uncertainty faced by the nuclear industry, and lastly inflation coupled with changing electricity demands served as a double blow for utilities as they had taken on large capital investments at unprecedented interest rates to meet demands that drastically declined from the 1960s to the 1970s (Isser, 2015; EIA, 2000).

The Carter administration responded to the events in the 1960s and 1970s, often referred to as the ‘energy crisis’, by enacting the National Energy Act in 1978. The National Energy Act was a comprehensive legislation designed to reduce United States’ dependency on foreign oil and its vulnerability to interruptions in energy supply, deregulate natural gas, encourage conservation, develop renewable and alternative energy sources, and tax energy consumption and imports (EIA, 2000; Isser, 2015). The National Energy Act included the Public Utility

¹² Such as transmission lines

¹³ While FPA gave FPC the jurisdiction over rates, terms, and conditions of service for interstate electricity transmission and wholesale electricity sales, it left regulation of generation, transmission, and intrastate commerce to State and local governments. This division of authority between federal and state/local governments over wholesale and retail rates respectively is often referred to as the “bright line”. The term “bright line” itself was coined by the Supreme Court in *Federal Power Commission v. Southern California Edison Co.* in 1964 (see EIA, 2017a).

¹⁴ The maximum thermal efficiency of pulverized coal power plants improved from 8% in 1900 to 40% in 1960 (Isser, 2015, p. 32).

Regulatory Policies Act (PURPA), Energy Tax Act, National Energy Conservation Policy Act, Power Plant and Industrial Fuel Use Act and the Natural Gas Policy Act.

The part of the National Energy Act that had a profound consequence—largely unintended—for the structure of the electricity industry was PURPA. Congress passed PURPA with an intent to increase conservation of energy supplied by electric utilities, to optimize the efficient use of facilities and resources by electric utilities, and to ensure equitable rates to electric consumers (Section 101)¹⁵. Section 210 of PURPA conferred upon certain non-utility generators called ‘qualifying facilities’ (QFs) special regulatory treatment to promote energy efficiency and “environmentally-preferable” generation (Watkiss & Smith, 1993, p. 453). PURPA further created a market for power produced at QFs by requiring local utilities to purchase power from these facilities at the utility’s own incremental or avoided cost of production rate¹⁶¹⁷. Before the enactment of PURPA independent power producers (IPPs) were faced with a situation where a disinterested monopsony, i.e. the local utility, did not have an incentive or obligation to purchase the QF’s ‘mongrel’¹⁸ power or provide it with transmission facilities (Watkiss & Smith, 1993)¹⁹. PURPA in effect changed this situation to the benefit of producers of power from QFs and in doing so opened the monopolistic electricity market to IPPs and spurred contracts between IPPs and vertically integrated utilities in states such as California, Texas, New York, and Massachusetts (Joskow, 1997; Elefant, 2011; FERC 2012; Flores-Espino et al., 2016, p. 8).

¹⁵ It must be noted here that Section 2 of PURPA included five other ‘findings’ that outline the intent of Congress in passing PURPA. These findings covered issues such as the need to-i) improve wholesale distribution and generation of electricity, ii) develop small scale hydroelectric facilities, iii) conserve natural gas and ensure that rates are equitable, iv) encourage the development of crude oil transportation system, and v) establish authority on matters related to the seasonal diversity of electric power to and from Canada. These additional findings were important from the standpoint of the electricity industry; however, they had a lesser influence on the overall *structure* of the industry itself compared to the provisions outlined in Section 101.

¹⁶ The law required electric utilities to purchase electricity from qualified facilities at “a rate which [does not] exceed the incremental cost to the electric utility of alternative electric energy . . . [which the] utility would generate or purchase from another source.” Public Utility Regulatory Policies Act of 1978, Section 210, Paragraphs (b) (2), and (d).

¹⁷ PURPA also required states (and utilities not regulated by states, such as public power and rural cooperative utilities) to conduct proceedings to consider charging cost-of-service rates for different customer classes, eliminating declining block pricing, using time-of-day, seasonal, or interruptible rates, and implementing other retail utility policies.

¹⁸ In his book ‘Grid: A Journey Through the Heart of Our Electrified World’ Phillip Schewe (2006) describes the challenges faced by utilities having to buy electricity from non-utility generators. He writes “[u]tilities now had to buy electricity from the independent producers (including factories with surplus electricity), providing the cost was lower than the cost it took the utility to make power for itself. The utilities were not thrilled. Their business was making and selling electricity, not buying it from other companies. Furthermore, since the *scheduling* of electricity— the perpetual balancing act between load and generation— is a tricky thing, it would be an imposition to have to buy orphan power in small amounts and at odd hours. The utilities didn’t like being forced to accept this mongrel electricity” (p. 172)

¹⁹ In practice, FERC used its discretionary authority to encourage open access. FERC imposed open-access transmission terms as a condition to approval of “market-based” rates under its general rate regulation authority, contained in sections 205 and 206 of the FPA. FERC initiated this policy with a flexible pricing experiment in bulk power transactions known as the Southwest Experiment (Isser, 2015, p. 110).

Although PURPA required utilities to purchase power from qualified facilities at avoided cost rates, access to transmission emerged as a key issue for QFs located outside the utility's service area (Isser, 2015). If, for example, a QF and a utility—say utility 1—that needed the QFs capacity and generation were located on either side of another utility—say utility 2—this utility 2 could decline the QFs request to use utility 2's transmission lines to “wheel”²⁰ power. In most cases utilities that would refuse such wheeling services were concerned about their own assets from being ‘stranded’ if their customers were buying generation from other sources that would prevent them from servicing the debt used to build generators (Howes, 1992, p. 18). Moreover, the Federal Energy Regulatory Commission (FERC) lacked the jurisdiction to mandate such wheeling (see 16 U.S. Code § 824k (h))²¹. Without access to wheeling services, competition in the wholesale electricity generation sector remained constrained.

The Energy Policy Act of 1992 (EPACT 1992) provided a solution to these transmission constraints and also created a new class of power producers—exempt wholesale generators²²—which together radically transformed the electricity industry. Section 721 of EPACT 1992 amended Section 211 of the FPA to empower electric utilities including cooperatives and municipal systems, federal power marketing agencies, or any other person generating electric energy for sale for resale to apply to FERC for an order to require a ‘transmitting utility’ to provide wholesale transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant. Moreover, a transmitting utility was to provide such a service at just and reasonable rates (Section 722 of EPACT 1992 amending Section 212 of FPA). These provisions opened up the possibility for wholesale wheeling. On the other hand, the creation of EWGs that were exempt from Securities and Exchange Commission under PUHCA eliminated a major barrier for utility affiliated and non-affiliated power producers to build ‘non-rate-based power plants’ in order to compete in the wholesale market for electricity (EIA, 2000). EPACT 1992 was also notable as it passed the first renewable electricity production tax credit (PTC) to encourage the development of renewable electricity generating resources. The PTC has been renewed and expanded numerous times, most recently by the American Recovery and Reinvestment Act of 2009, the American Taxpayer Relief Act of 2012, the Tax Increase Prevention Act of 2014, the Consolidated Appropriations Act of 2016 and the Bipartisan Budget Act of 2018 (Department of Energy, 2018).

²⁰ Wheeling occurs when a transmission-owning utility allows another utility or independent power producer to move (or wheel) power over its transmission lines.

²¹ Further analysis and history on FERC's authority on wheeling is covered by Downs and Driver (1998). ‘Can FERC Lawfully Order Transmission Providers to Participate in an ISO? Will it Anyway?’ pp. 16-18, and Watkiss and Smith (1993) pp. 456-459.

²² Under Section 32 of the PUHCA, an exempt wholesale generator is defined as “any person determined by the Federal Energy Regulatory Commission to be engaged directly, or indirectly through one or more affiliates..., and exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities and selling electric energy at wholesale.”

FERC began implementing its wheeling authority immediately after EPACT 1992 was passed; however, wheeling requests by applicants were evaluated on a case-by-case basis and involved significant time delays (FERC, 1996a). This in turn placed the applicant at a severe disadvantage compared to the transmission owner (FERC, 1996a). In the Spring of 1994, FERC also began addressing issues of disparity in transmission service that utilities provided to third parties in comparison to their own uses of the transmission system through the implementation of a comparability standard (FERC, 1996a). FERC applied the comparability standard as well on a case-by-case basis. Despite more wheeling authority and implementation of comparability standards, open non-discriminatory transmission access did not yet exist universally. To correct this lack of universal non-discriminatory transmission access and ensure a ‘successful transition to competitive wholesale electricity markets’, FERC issued Order 888 in April 1996 (FERC, 1996a, p. 51).

FERC Order 888 had two components: non-discriminatory open access transmission services and stranded cost recovery (FERC, 1996a). The first component required transmission owning utilities to file open access transmission tariffs specifying the terms and conditions for using their transmission services. It also required ‘functional unbundling of wholesale generation and transmission services as a necessary step towards implementing non-discriminatory open access transmission services. FERC issued Order 889 in tandem with Order 888 to aid the implementation of functional unbundling of generation and transmission services²³. FERC Order 889 spelled out the requirements for creating standards and protocols for functionally unbundling generation and transmission functions within the same public utility and for creating an Open Access Same-time Information System (OASIS) that would be accessible by all qualified users of the transmission system to obtain information on transmission capacity, capacity reservation, ancillary services, and transmission prices (FERC, 1996b). FERC Order 888 also required transmission owning utilities to include six essential ‘ancillary’ services²⁴ in their open access transmission tariffs (FERC, 1996a, p. 199). A transmission provider was mandated to offer these six ancillary services to transmission customers, which the customer was mandated purchase these services from the provider in order to ensure grid reliability.

The second component of FERC Order 888, i.e. stranded cost recovery, specified how and from whom utilities could recover their stranded costs. FERC’s rationale for including this

²³ More recently, FERC has issued Order 890 to reform the *pro forma* open access transmission tariff to clarify and expand the obligations of transmission providers to ensure that transmission service is provided on a non-discriminatory basis (FERC, 2007). FERC has also issued Order 1000 that reforms the Commission’s electric transmission planning and cost allocation requirements for public utility transmission providers (FERC, 2018; FERC, 2011). The rule builds on the reforms of Order No. 890 and corrects remaining deficiencies with respect to transmission planning processes and cost allocation methods (FERC, 2018).

²⁴ In Order 888, FERC defines the following ancillary services: (1) Scheduling, System Control and Dispatch Service, (2) Reactive Supply and Voltage Control from Generation Sources Service, (3) Regulation and Frequency Response Service, (4) Energy Imbalance Service, (5) Operating Reserve – Spinning Reserve Service, (6) Operating Reserve – Supplemental Reserve Service.

second component in Order 888 was “to gain support and cooperation” from transmission utilities that had invested billions of dollars in facilities for a successful transition to a competitive industry (EIA, 2000, p. 64). As such while PURPA sowed the seeds for increasing competition in the electric power industry, it was EPACT 1992 coupled with FERC Order 888 and 889 that created greater transmission access and facilitated the creation of competitive wholesale electricity markets in the United States.

In the 1990s, the passage of EPACT and FERC Orders 888 and 889 fomented a surge in activity at State legislatures and utility commissions to examine various issues with respect to the electricity industry. States passed laws and policies to promote industry competition at the retail level and to complement FERC’s initiatives at encouraging wholesale wheeling and stranded cost recovery (EIA, 2000). The federal and state initiatives during this period, taken together, are often couched under the umbrella term of industry ‘restructuring’²⁵.

During the course of Order 888 proceedings, the FERC received comments urging it to create regional independent system operators (ISOs)²⁶ to better assure non-discrimination in transmission provision and access. However, FERC believed that a less intrusive functional unbundling approach was all that was needed at the time, but, utilities could choose to use ISOs as tools to meet the demands of the competitive marketplace (FERC, 1996a, p. 31). In the four years following the passage of Orders 888 and 889, FERC observed that the transmission grid was being used more intensively and in different ways than in the past (FERC, 1999, p. 16). This increased the stress placed on the existing transmission system, made coordinating the use of the transmission system more challenging than ever, made discriminatory behavior with regard to transmission access subtler and more difficult to identify, and highlighted the threat to grid reliability²⁷. To address these issues, FERC passed Order 2000 in December 1999. The goal of Order 2000 was to form regional transmission organizations (RTOs) voluntarily and in a timely manner (FERC, 1999, p. 8). Order 2000 delineated twelve characteristics and functions that an entity must satisfy in order to become an RTO (FERC, 1999). FERC Orders 888 and 2000 consequently resulted in the creation of several ISOs and RTOs and pushed electricity markets even further; while Order 888 was the primary motivation for creation of New England and PJM

²⁵ Restructuring actions vary by region and by state, but they are typically characterized by the unbundling of ownership and regulation of electricity generation, transmission, distribution, and sales, with large variations in how restructuring is implemented across regions and states (EIA, 2017a, p. A-13). The history of electricity restructuring is covered by notable historian Richard Hirsh in ‘Power loss: The origins of deregulation and restructuring in the American electric utility system’ (1999), and scholar of energy law and economics Steve Isser in ‘Electricity Restructuring in the United States: Markets and Policy from the 1978 Energy Act to the Present’ (2015).

²⁶ ISOs operate the transmission system independently of, and foster competition for electricity generation among, wholesale market participants (FERC, 2017a).

²⁷ FERC grouped these various issues under two broad categories of impediments to a competitive wholesale electric market: (1) the engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid, and (2) continuing opportunities for transmission owners to unduly discriminate in the operation of their transmission systems so as to favor their own or their affiliates’ power marketing activities. (FERC, 1999, p. 32)

markets, Order 2000 was the impetus that encouraged the creation of Midwest and Southwest markets (Isser, 2015, p. 225). At present, two-thirds of the nation's electricity load is served in RTO regions (FERC, 2017a).

The last major comprehensive law that addressed several major areas of the electricity industry was the Energy Policy Act of 2005 (EPACT 2005). EPACT 2005 significantly expanded FERC's responsibilities and authority with the goal of promoting wholesale electricity competition, protecting consumer interests in the wake of changing electricity industry structure, developing stronger energy infrastructure in the country (FERC, 2006). To this end, FERC was entrusted with the responsibility for overseeing the reliability of the nation's electricity grid, implementing tools to prevent market manipulation, providing rate incentives for promoting transmission development, supplementing state transmission siting in electric transmission corridors of national interest, and reviewing certain holding company mergers and acquisitions (FERC, 2006). In addition to expanding FERC's authority and responsibilities, EPACT 2005 included other major provisions such as paring back of the must-purchase clause in PURPA in areas where utilities had access to competitive wholesale markets, repealing PUHCA 1935 and implementing in its place a new PUHCA 2005, encouraging Tribal energy development, and authorizing loan guarantees for the innovation and development of clean power technologies.

The net result of changes in federal laws and policies pertaining to the energy industry, changes in the industry structure and rise in competitive markets is that the United States today has a patchwork of laws and policies governing the electricity industry and a diverse set of industry participants. In addition, the growth in federal incentives for renewable energy development, such as through the PTC, as well as state level incentives²⁸ and goals for increasing renewable energy generation, such as through renewable portfolio standards, renewable energy credits, feed in tariffs, and net metering tariffs, has spurred the development of renewable generation—especially wind and solar—and has brought about a change in the mix of capacity addition and electricity generation in the United States (EIA, 2017b)²⁹. Of the total utility-scale capacity additions in 2016, for example, more than 60% were wind (8.7 GW) and solar (7.7 GW), compared with 33% (9 GW) from natural gas (EIA, 2017b). In 2017, renewable energy sources accounted for almost 17 percent of the total electricity generation in the nation (EIA, 2018a).

The changes in industry structure, rise in competitive markets, and growth in renewable energy generation has in turn brought about a change in the role and importance of hydropower in the electricity sector. Whereas hydropower's contribution to the net electricity generation has decreased from 30 percent in the 1950s to 7 percent in 2017 and the installation of new

²⁸ The website <http://programs.dsireusa.org/system/program?type=38&technology=10&> provides an overview of state level policies and incentives for renewable energy development.

²⁹ See also EIA's (2017) chart of U.S. utility-scale electric capacity additions and retirements from 2002 to 2016.

hydropower capacity in the United States has declined since the mid-1990s, these trends do not capture the growing importance of hydropower’s strategic role in the electricity sector (Department of Energy, 2016a; EIA, 2018b). Due to the flexibility and quick response capabilities of hydropower facilities, hydropower generators are “excellent” for providing regulation and load following and can also provide contingency reserves depending on their operating constraints (Sandia National Laboratories, 2011, p. 9). As most hydro generating facilities use synchronous machines, they are capable of providing voltage regulation (Sandia National Laboratories, 2011; Key, 2013). Hydro facilities can also provide black-start capability. Hydropower can thus provide significant contribution to the power system reliability by providing energy, capacity and most, if not all, ancillary services identified by FERC (in Order 888) and the three essential grid reliability services—frequency response, ramping, and voltage support—identified by the North American Electric Reliability Corporation (NERC)³⁰ (Sandia National Laboratories, 2011; Acker & Pete, 2012; Department of Energy, 2016a, p. 96). Along with its ability to provide system reliability, hydropower is and will continue to be an important resource in the rapidly evolving electricity sector as it can facilitate the deployment of intermittent renewable energy resources, such as wind and solar, by managing net-load variability and provide ancillary services that are valuable in competitive markets (Key, 2013; Department of Energy, 2016a).

2.1.3.2 Colorado River Basin Energy Laws and Policies

When Congress passed the Reclamation Act of 1902, it did not foresee the Federal Government playing a role in the generation and transmission of electricity. In its earliest construction projects, however, Reclamation recognized the potential of electric power from its water storage facilities (Rowley, 2006). To address the void that Reclamation Act left with respect to Federal participation in development of hydroelectricity, Congress passed the Town Sites and Power Development Act in 1906. This act was instrumental in the history of Federal power development in two ways. Both these ways can be traced to Section 5 of the Act.

First, the act recognized that development of power could be a necessary component for irrigation of lands under Reclamation Act of 1902 and gave the Secretary of the Interior the power to authorize the lease of hydropower from reclamation facilities for a period of ten years. The necessity of development of power at reclamation facilities and the grant of power to the Secretary of the Interior paved the way for Federal Government’s entry into the electric power field (United States General Accounting Office [hereafter GAO], 2001; WAPA, 2002). Second, it gave preference to municipal purposes in the sale of surplus power or lease of power privileges³¹. Municipal purposes included such uses as street lighting (GAO, 2001). While the

³⁰ See NERC, 2014

³¹ A Bureau of Reclamation lease of power privilege (LOPP) is a contractual right given to a non-federal entity to use a Reclamation asset (e.g. dam or conduit) for electric power generation consistent with Reclamation project purposes (Reclamation, 2018).

preference concept did not originate with the Town Sites and Power Development Act of 1906³², this act was the first to apply this concept to power generated at reclamation facilities and set the course for defining who could receive power from reclamation projects in the future.

With the entrance of the Reclamation Service into the business of power production and distribution began a bitter and long-standing controversy between private and public power advocates over hydropower development³³. This controversy revolved around issues that were the same as those that divided opinions about any role of government in the electric utility industry, however, the unique characteristics of hydropower³⁴ provided stronger justification for government involvement than any other parts of the industry (Linenberger, 2002; Neufeld, 2016). Private power companies feared the competition from public power—dams and power plants built by not only the federal government but also states and municipalities—as the private power industry was attempting to secure power sites and provide services to cities under the conditions of a “beneficial monopoly” (Rowley, 2006, p. 153). Public power advocates on the other hand aimed to deliver the power generated at hydropower sites more widely, including rural areas that private utilities considered unprofitable to serve (Linenberger, 2002, p. 42)³⁵. Against this backdrop of growing conflict between conservationists, progressives and others who were suspicious of profit-seeking private power companies and their sympathizers, Congress saw a sharp increase in the number of bills requesting approval for specific projects as the demand for new hydroelectric facilities grew (Neufeld, 2016). At that time, three cabinet secretaries were involved in giving approval for waterpower projects: Agriculture, Interior, and War. The policies of the three departments often conflicted and tended to change with administrations (Neufeld, 2016, p. 158). To create a streamlined process for the development of waterpower, Congress passed the Federal Water Power Act in 1920.

The Federal Water Power Act symbolized a significant victory for public power as it protected federal involvement in hydropower development even as it promoted and regulated private power (Linenberger, 2002). The act created the Federal Power Commission (FPC)—an agency that would later become an important regulator of the electricity industry— comprised of the Secretaries of Interior, War, and Agriculture and gave it the power to issue licenses for the

³² The concept of preference customer has its origins in the Desert Land Act of March 3, 1877. It was the first Federal statute that stipulated that surplus reclamation and other non-navigable water on public lands was for the use of the public— “all surplus water over and above such actual appropriation and use, together with the water of all, lakes, rivers and other sources of water supply upon the public lands and not navigable, shall remain and be held free for the appropriation and use of the public”.

³³ Several notable scholars have covered this piece of history in their work. For brief overviews see Chapter 8 ‘Hydroelectricity and the Federal Government’ in John L. Neufeld (2016) ‘Selling power: economics, policy, and electric utilities before 1940’, and Rowley (2006) ‘The Bureau of Reclamation: Origins and Growth to 1945 Volume 1’ pp. 152-154.

³⁴ That is, hydropower as a use of water that had multiple other uses and hydropower’s ability to generate power at very low total costs.

³⁵ The other well-known, but highly debated, argument for federal role in hydropower development was that federal investment in multipurpose dams that generated hydropower would force down private rates under a “yardstick” principle (Linenberger, 2002, p. 44; Neufeld, 2016, p. 179).

construction and operation of hydroelectric facilities on both navigable waterways and public lands for a period of 50 years. Section 7(a) of the act required the newly created FPC, when faced with a tie between competing equal applications, to give preference to states and municipalities in awarding preliminary permits and subsequent licenses. The FWPA also marked an important point in the evolution of the preference clause used in marketing of Federal hydropower. With the passage of FWPA in 1920, the preference clause evolved from serving a specific purpose, i.e. ‘municipal purpose’ under the Town Sites and Power Development Act of 1906, to serving specific classes of users such as public bodies and cooperatives. The FWPA therefore considerably broadened the type of customers that could receive hydropower generated at reclamation facilities.

Congress further expanded the class of preference customers and clarified the terms of power sales contracts from reclamation projects by passing the Reclamation Project Act of 1939. Section 9(c) of the act contained three important provisions: (i) it established the maximum term of 40 years for all reclamation power sales contracts (either direct sales or lease of power privilege), (ii) it required that such contracts produce sufficient revenue to cover an appropriate share of the construction costs, annual operation and maintenance costs and interest on investment along with any other fixed costs, and (iii) that for sales and leases, preference shall be given to municipalities and other public corporations and agencies, along with cooperatives and other nonprofit organizations that were financed in whole or in part by loans made through the Rural Electrification Act of 1936. The Secretary of the Interior remained the authority responsible for executing these power contracts. As the Reclamation Project Act of 1939 defined the broader terms for all future power contracts, Western Area Power Administration³⁶ (or alternatively WAPA in this paper) called it “the single most important piece of legislation” affecting its power marketing activities (WAPA, 2002, p. 7).

Five years after the Reclamation Project Act was passed, Congress passed a legislation that expanded the power of the Secretary of the Interior to market power generated at reservoirs under the control of War Department. This was the Flood Control Act of 1944. When electricity was generated at dams controlled by the War Department (i.e. the Army Corps of Engineers facilities) but not required for the operation of the project, Section 5 of the act gave the Secretary of the Interior the responsibility to “transmit and dispose of such power and energy *in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers* consistent with sound business principles, the rate schedules to become effective upon confirmation and approval by the Federal Power Commission” (emphasis added). Section 5 also underscored the preference clause in sale and marketing of power.

While the provisions of the Flood Control Act of 1944 did not explicitly mention reclamation facilities, a 1965 letter by Secretary Udall to Representative Aspinall confirmed that

³⁶ more on Western Area Power Administration in the subsequent paragraphs

provisions of Section 5 did in fact apply to reclamation facilities. The argument posed by Secretary Udall was that the provisions relating to power marketing and power rates in Section 9(c) of the Reclamation Project Act of 1939, Section 5 of the Flood Control Act of 1944, and Section 6 of the Bonneville Power Act were “*in pari materia*”, and each may be examined to shed light on the Congressional intent with respect to others. Consequently, the mandate of the Flood Control Act of 1944 to market power from Army projects to encourage widespread use at lowest possible rates applied also to power marketed from reclamation projects under reclamation law (Flood Control Act of 1944, Secretary Udall to Representative Aspinall 1965 in Notes of Opinions, p. 801). This provision on widespread use and lowest possible rates has had a profound impact on power marketing from reclamation facilities; this provision along with the preference clause has been the source of some bitter conflicts in reclamation’s power marketing activities as well as the source of WAPA’s authority in changing power allocations made to existing customers. Not only that, this provision is one of the fundamental reasons why power from reclamation facilities continues to remain economically attractive for customers in the face of an unprecedented drought as will be discussed in Section 2.3 (under Question 2). Secretary Udall in his 1965 letter famously said, “[t]he Government of the United States markets power to serve the public interest, not to make a profit. We believe that the public interest is best served by marketing power at the lowest rate consistent with orderly repayment of all proper costs, and we believe that is what Congress intended”³⁷.

At the constitutional level, the Flood Control Act of 1944 proved to be the last major influencer of provisions governing power marketing and allocation. This said, specific project characteristics (and politics) resulted in some deviations from the power marketing principles laid down at the constitutional level, especially in the case of Hoover Dam. The laws and policies that authorized these changes will be discussed in turn at the collective choice level in Section 2.2.3.

From 1902 to 1977, Secretary of the Interior retained the responsibility to market power from reclamation facilities. This changed with the passage of the Department of Energy Organization Act in 1977. This act is notable in the history of the energy industry as it created the Department of Energy (Section 102) as well as the Federal Electricity Regulatory Commission (FERC) (Section 204, Section 401 (a)). It transferred all functions of the FPC to the newly established FERC³⁸ (Section 301 (b)). Section 302 (a) of this act transferred all the power marketing functions from the Department of the Interior (and consequently Secretary of the Interior) under Section 5 of the Flood Control Act to the newly created Secretary of Energy. This included the transfer of power marketing functions of the Secretary of the Interior along with the responsibility of constructing, operating, and maintaining transmission lines. Section 302 (a)(3)

³⁷ The letter from Secretary Udall to Representative Aspinall was on the subject titled ‘Basis for establishing power rates for the Colorado River Storage Project’.

³⁸ For a full list of functions undertaken by FERC, please see <https://www.ferc.gov/about/ferc-does.asp>

of the act further required the creation of separate administrations within the Department of Energy to carry out Department of Interior's erstwhile power marketing functions. The resultant effect of the requirements under Section 302 was the creation of WAPA to take over Reclamation's responsibilities³⁹.

The transfer of power marketing functions from Reclamation to WAPA was the last pertinent change in constitutional-level provisions that defined who could market power from reclamation facilities. Since it assumed its power marketing responsibilities in 1977, WAPA remains the agency responsible for marketing the power generated at Hoover and Glen Canyon Dams, while Reclamation continues to operate these dams.

Federal Energy Laws and Policies: Applicability to Western Area Power Administration's Operations

As a federal power marketing administration, Western Area Power Administration is unlike any other utility in the electric power industry. WAPA does not own any generation assets or sell power to directly to customers like municipal utilities, electric cooperatives or IOUs, and neither does it sell electricity for a profit like power marketers. WAPA markets electricity generated by federally owned facilities at the wholesale level. Its operations are primarily governed by a host of constitutional-choice level laws discussed in Section 2.1.3.2 and project-specific laws and policies discussed in Section 2.2.3. Many of these laws and policies are unique to the agency, such as the Reclamation Project Act of 1939.

The applicability of major federal laws and policies that have affected the structure of the electricity sector to WAPA's operations has increased over time primarily through the enlargement of FERC's jurisdiction over power marketing administrations. With the addition and subsequent amendment of Section 211 of the Federal Power Act by PURPA and EPACT 1992 respectively, WAPA was brought under FERC's jurisdiction, albeit to a limited degree, on matters related to provision of transmission services to applicants requesting such services. EPACT 2005 further expanded FERC's jurisdiction over WAPA in four areas: electricity reliability⁴⁰, rates, compliance with certain provisions of FPA, and open access transmission. As WAPA is not a public utility, FERC did not have legal authority over WAPA's rates and charges

³⁹ WAPA was the only 'new' power marketing administration that was created under the Department of Energy Organization Act of 1977. At the time, four other administrations—Southeastern Power Administration, Southwestern Power Administration, Alaska Power Administration, and Bonneville Power Administration—already existed within the Department of the Interior. These administrations retained their power marketing responsibilities and were moved over to the newly created Department of Energy from Interior.

⁴⁰ Under the EPACT 2005, electricity reliability was brought under FERC's jurisdiction (See Title XII, Subtitle A-Reliability Standards). All users, owners and operators of the bulk-power system are required to comply with the reliability standards set forth by the Electric Reliability Organization, i.e. NERC, which are ultimately approved by FERC.

related to transmission and sale of electricity,⁴¹ and prior to 2005, could not mandate WAPA to follow the open access transmission provisions under Orders 888 and 889. In practice, however, a directive by the Secretary of Energy gave FERC the authority to confirm and approve the rates charged by WAPA⁴², and WAPA voluntarily chose to follow FERC Orders 888 and 889 as a major transmission owner in Western U.S. (WAPA, 2012). With respect to rates and open access transmission then, EPACT 2005 clarified the standard of review that FERC would use in examining WAPA's rates and gave FERC the authority to order WAPA to offer comparable open access transmission service under terms that are not unduly discriminatory and preferential (WAPA, 2012). EPACT 2005 also increased WAPA's obligations to comply with filing rate schedules with FERC as well as providing notices of rate changes in accordance with Section 205 (c) and (d) of FPA. As such, from an operational standpoint, the two federal policies that have had the biggest impact on WAPA's day-to-day operations over the last two decades have been FERC Orders 888 and 889 as they have required WAPA to identify its transmission needs with greater accuracy (Interview with staff at WAPA, 2018).

2.2 Collective-choice Level

The collective-choice level institutional structures comprise of a host of laws, record of decisions, inter-state/agency agreements and compacts, administrative rules, and outcomes of court decisions. These institutional structures cover a wide range of issues ranging from intra-state and inter-state water allocation, acreage limitation for irrigation, payment of taxes etc. Using the analytical lens discussed in Section 1.1.2 the discussion of institutional arrangements at the collective-choice level has been carried out in a chronological order with a focus— a) the specific institutional provisions (water and environment) that govern dam operations and hydropower generation, specifically those pertinent to Hoover and Glen Canyon Dams, b) the relationships between hydropower generation and other water uses (irrigation and environment) especially from an economic standpoint, and c) the specific institutional provisions that govern marketing and allocation of power from Hoover and Glen Canyon Dams and serve as the basis for developing and enforcing electric service contracts with prospective power customers. At the collective-choice level, the discussion of power contracts has been limited to the contract duration and major contract provisions, such as the ability of power customers to resell power. The discussion of specific contract terms that have a greater impact on day-to-day dam operations and electricity generation could have been discussed in this section like water and environmental laws; however, as these contract terms are easier explained in context, they have been discussed at the operational level in Section 2.3 under Question 1.

Like the constitutional-choice level, the collective-choice level institutional arrangements have been discussed under three subsections: water, environment, and energy laws and policies.

⁴¹ That is, FERC's jurisdiction over public utilities under Sections 205 and 206 of the FPA

⁴² The directive is renewed every few years. The most recent directive, signed November 19, 2016, is accessible here: <https://www.directives.doe.gov/delegations-documents/037.000b/@/@images/file>

2.2.1 Water Laws and Policies

The first legislation passed to operationalize the intent of the 1922 Compact was the Boulder Canyon Project Act of 1928 (BCPA 1928). This act authorized the construction of Hoover Dam (Hoover) and required that the dam be used first for river regulation, improvement of navigation, and flood control⁴³, second for irrigation and domestic uses and satisfaction of present perfected rights, and third for power generation (Section 6 BCPA 1928). However, before any money could be appropriated for the construction of the dam or power plant, the Secretary of the Interior was required to make provision for revenues that would be sufficient to cover the construction, operation and maintenance costs of the dam with the added consideration that initial federal investments had to be repaid within a 50-year period (Section 4(b) and 5(a) of BCPA 1928). Given the poor performance of agricultural users—the primary beneficiaries of irrigation/reclamation project—with respect to the repayment for the irrigation projects, it was anticipated that these construction and operation and maintenance expenses would be recovered through sale of hydroelectricity (Rowley, 2006). The Town Site and Power Development Act of 1906, had recognized the potential to use hydropower revenue to pay for irrigation projects (Section 5), but it required the Secretary of the Interior to give preference to such power to municipal purposes, i.e. public purposes. When it came time to contracting for the dam’s hydropower, however, the exorbitant cost of constructing, operating and maintaining the dam could only be borne by economically powerful utilities, public and private, in California. By 1930, the Secretary of the Interior Ray Lyman Wilbur negotiated over \$327,000,000 in electrical contracts for the sale of Hoover power with Southern California Edison, City of Los Angeles Water and Power, and Metropolitan Water District confirming what Congress had been promised: the big dam would pay for itself⁴⁴ (Rowley, 2006, p. 279). The inclusion of a private utility as a beneficiary of Hoover is important to note here as this was an exception; in the case of Glen Canyon, along with other reclamation facilities, all power customers were typically public entities (see Section 2.2.3 for further discussion).

Although it was clear through the BCPA 1928 that the economic burden of building and maintaining infrastructure in the Basin was to be shouldered by energy users, an amendment to the Reclamation Act, further formalized this cost calculus for all future reclamation projects. Reclamation Project Act of 1939, required agricultural users to pay for construction charges of the project commensurate with their ‘ability to pay’ (Section 1), and they were exempt from paying operational and maintenance costs (Section 2). The irrigators’ ability to pay was deemed low at the time due to decline in ‘agricultural income and unsatisfactory conditions for agriculture’ (Section 1). The Reclamation Project Act of 1939 allowed the sale of electric power and required the setting of rates at a level so as to produce revenues that could cover annual

⁴³ The fact that river regulation, navigation, and flood control received first priority of use of the reservoir storage (contrary to the 1922 Compact where navigation had the lowest priority), was a direct result of severe annual flooding that impacted lower reaches of the Colorado River before Hoover Dam was constructed (Nathanson, 1978).

⁴⁴ As a point of comparison, the initial federal funds advanced for the construction of the project were \$165 million (Section 2b, Boulder Canyon Project Act 1928).

operation and maintenance costs of the infrastructure and could reimburse construction investments at a 3 percent interest rate (Section 9 (c)). Electricity sales, thus became the “paying partner of irrigation” (Rowley, 2006, p. 153).

It took over one and a half decade after the passage of the Reclamation Project Act of 1939 for any kind of infrastructure planning to begin in the Upper Basin. This was due to the fact that Upper Basin states apportioned their allocation of the Colorado River only in 1948 by passing the Upper Colorado River Basin Compact (UCRBC 1948). This Compact finally created conditions to initiate dam development as it authorized the construction of dams and allowed storage of water for agricultural and domestic needs and generation of electricity (Article XV UCRBC 1948).

After the passage of the UCRBC 1948, the Upper Basin States signed the Colorado River Storage Project Act in 1956 (CRSP 1956), which authorized the construction of Glen Canyon, Curecanti, Flaming Gorge, and Navajo Dams to meet power, irrigation, municipal water supply, flood control, navigation, or any other purposes stated under reclamation law (Section 6). Of the four storage reservoirs formed by the four dams, Lake Powell was the largest and most important; this reservoir was built to meet the 1922 Compact obligations of the Upper Basin states at Lee Ferry (Kuhn, 2016).

CRSP 1956 was similar to BCPA 1928 in structuring the use of water in the reservoirs, in that, hydropower was deemed subservient to other water uses. What was different about CRSP 1956 than BCPA 1928 was that the act— a) required the operation of hydroelectric power plants and transmission lines “in conjunction with other federal power plants, present and potential, so as to produce the *greatest practicable amount of power and energy that can be sold at firm power and energy rates*” (Section 7, emphasis added), b) authorized the use of electricity revenues for ‘assisting in the pay-out of costs of participating projects (current and future) authorized in the States of Colorado, New Mexico, Utah, and Wyoming’ (Section 13), along with repayment for the dams themselves, and c) was passed after Reclamation Project Act of 1939, which required that preference for sale/lease of power from reclamation facilities be given to municipalities and other public corporations or agencies, cooperatives and other nonprofit organizations (Section 9(c), Reclamation Project Act 1939). These three conditions, have had immense consequences for the economics of building and maintaining irrigation infrastructure in the Upper Basin; the viability of the four Colorado River Storage Project dams and 16 major participating irrigation projects is tied to electricity revenues that are deposited in the Upper Colorado River Basin Fund (Reclamation, 2011). The differences in CRSP 1956 and BCPA 1928 have also been profoundly important from the perspective of power marketing and contracting as the types of contracts, and the number and type of utilities that receive power from these Upper Basin reservoirs is different than Hoover Dam as will be discussed further in Section 2.2.3.

After the passage of CRSP 1956, and the completion of construction of Glen Canyon Dam, the seven Basin states were negotiating with each other and Congress over the Colorado Basin Project Act, which ultimately passed in 1968 (CRBPA 1968). The Upper Basin States' representative were concerned that the Lower Basin States would interfere with the storage and operation of Lake Powell by using Article III (e) of the 1922 Compact, which prohibited the Upper Basin States to withhold water that could reasonably be applied to agricultural or domestic uses in the Lower Basin. This concern prompted the including of Section 602 (a) in the CRBPA, which required the preparation of long-range operating criteria and setting priorities for releases of water from Lake Powell. This was the first, and arguably foundational, collective-level provision that dictated the coordinated operation of reservoirs of Hoover and Glen Canyon Dams.

CRBPA 1968 was also important as it authorized several irrigation projects in both Lower and Upper Basins along with the Central Arizona Project. Title IV of the CRBPA 1968, authorized the creation of a Lower Colorado River Basin Development Fund where a portion of revenues from sale of electricity from Hoover dam could be used to defray the CAP. Following the requirements of the CRBPA 1968, the Secretary of the Interior passed the Criteria for Coordinated Long Range Operation of Colorado River Reservoirs in 1970 (LROC 1970), which set the broader framework within which Hoover and Glen Canyon Dams are now operated. LROC 1970 requires the Bureau of Reclamation to prepare annual operational plans as a single integrated reference document for managing reservoirs created as part of CRSP 1956 and BCPA 1928 (i.e. reservoirs of Glen Canyon, Curecanti, Flaming Gorge, Navajo, and Hoover Dams); these plans set the annual water releases that are expected to be made out of the dams, however, these plans do not modify the authority of the Secretary to determine monthly, daily, hourly or instantaneous releases from Glen Canyon or Hoover Dam (Department of Interior [hereafter Interior], 2007, p. 23).

Under the LROC 1970 the main requirements that govern operations of Upper Basin reservoirs are that—(a) releases out of Lake Powell have to be maintained at a minimum of 8.23 million acre-feet per years (Article II, Section 2 (b)), (b) in case of higher levels of water availability in Lake Powell, release of water so as to equalize active storage in Lakes Mead and Powell (Article II, Section 3(b)), to the extent that such a release can be passed through Glen Canyon Power plant when operated at the available capacity (Article II, Section 4). For the Lower Basin, the LROC 1970 identified three operational situations based on water availability—normal (7.5 million acre-feet), surplus (> 7.5 million acre-feet), and shortage (<7.5 million acre-feet)—and provided guidelines on releases out of Lake Mead based on the identified

situation⁴⁵. The LROC 1970 conditions, simply put, mean that Lake Powell operations have to ensure-a) compliance with the requirements of 1922 Colorado River Compact, b) in years of excess active storage release additional water so as to meet the 10-year delivery requirement of 7.5 million acre-feet, and c) make such releases in a way so as to generate hydroelectricity at available capacity at Glen Canyon Dam.

The LROC 1970 were the only criteria governing operations of Hoover and Glen Canyon Dam until the 1990s; however, a change in hydrological conditions and increase in the demand for Colorado River water propelled the adoption of additional reservoir management strategies for effectively coordinating the operations of Lake Powell and Lake Mead. From 2001 to 2007 three strategies were adopted: Colorado River Interim Surplus Guidelines of 2001 (ISG 2001), Interim 602 (a) Storage Guidelines of 2004, and Colorado River Interim Guidelines for Lower Basin Shortages and the Coordinated Operations for Lake Powell and Lake Mead of 2007 (2007 Interim Guidelines).

The ISG 2001 were adopted by Secretary of the Interior Bruce Babbitt as a framework to aid California in developing and implementing a plan to reduce its consumptive use to 4.4 million acre-feet⁴⁶. The ISG remained in effect until 2016, and served as a guideline in identifying the specific amount of surplus water which may be available in a given year based on Lake Mead elevation, along with the excess water allocation criteria in a surplus situation (Interior, 2001, pp. 21-23). ISG kicked in while framing annual operational plans; therefore, these guidelines affected annual-level water availability and apportionment and did not specifically impact monthly, daily, or hourly operations of Hoover Dam.

Interim 602 (a) Storage Guidelines (602 (a) Guidelines) were implemented by the Reclamation to clarify conditions under which Lake Powell releases had to be made to equalize active storages in both Lakes Powell and Mead pursuant to the LROC 1970 (Interior, 2004). 602 (a) Guidelines required releases to be made out of Lake Powell to equalize the active storage in Lake Mead if Powell's lake elevation was 3630 feet, if the water level was lower than this mark, releases only had to be made to maintain a minimum annual release of 8.23 million acre-feet (i.e. the amount necessary to meet Lower Basin and Mexican Treaty obligations). While ISG applied to Lake Mead, 602 (a) applied to Lake Powell and affected the annual operational plan of Glen Canyon Dam; like the ISG however, these guidelines did not impact the monthly, daily, or hourly operations of the dam.

⁴⁵ Arizona v California, 1964 has not been discussed in this paper as it does not impact operations of Hoover Dam. In the context of the LROC, the Arizona v. California Consolidated Decree 2006 likewise does not influence how Hoover Dam is operated, but it does determine how water is allocated under surplus and shortage situations.

⁴⁶ In almost all the years from 1953 through 2003, California's consumptive use of Colorado River water exceeded its annual apportionment of 4.4 million acre-feet under normal water availability conditions.

While these two guidelines were being used to govern operations of Hoover and Glen Canyon, the sustained drought (worst in 100 years of recorded history), low natural-flow conditions in Lake Powell (lowest 9-year average since 1906), over-use of water by Lower Basin States, drop in combined reservoir storage level in Lakes Mead and Powell from 95 percent in 1999 to 46 percent in 2004, propelled the seven Basin States and Bureau of Reclamation to identify guidelines to better share the risk of drought years (Verburg, 2010). The 2007 Interim Guidelines were thus signed to remain in effect until 2025 and included four elements: shortage guidelines which identified circumstances under which water deliveries to Lower Basin could be reduced under the apportioned 7.5 million acre-feet, coordinated operation guidelines for Lakes Powell and Mead, guidelines for storage and delivery of conserved water and interim surplus guidelines for Lake Mead (Interior, 2007). The 2007 Interim Guidelines provide an objective methodology to determine the annual releases from Lake Powell and Lake Mead, unless an unforeseen/extraordinary circumstance prevents such releases. Like ISG, and 602 (a) Guidelines, the 2007 Interim Guidelines do not dictate or affect monthly, daily, or hourly operations of the two dams.

2.2.2 Environmental Laws and Policies

After the passage of NEPA 1969 and ESA 1973, several programs were developed in both the Upper and Lower Basins to protect endangered species⁴⁷. Environmental concerns also prompted the passage of the Grand Canyon Protection Act in 1992, which was specifically applicable to Glen Canyon Dam. As the nature of environmental programs, and specific records of decision that were passed differ considerably for Hoover and Glen Canyon Dams, these will be discussed in turn below.

Hoover Dam

In the Lower Basin, prior to 1994, Reclamation addressed ESA compliance issues on an action-by-action basis (Verburg, 2010). In 1994 the US Fish and Wildlife Service (USFWS) designated 1980 miles of the Colorado River and its tributaries as critical habitat for four fish species: humpback chub, Colorado pikeminnow, bonytail, and razorback sucker (59 Fed. Reg. 13374, 1994). The designation of critical habitat pushed various stakeholders in the Lower Basin—Reclamation, USFWS, National Park Service, Bureau of Indian Affairs, Bureau of Land Management, Western Area Power Administration, and state-level resource users in California, Arizona, and Nevada—to consider a comprehensive program for meeting ESA requirements, as opposed to an action-by-action approach (Lower Colorado River Multi-Species Conservation Program [hereafter LCR MSCP], 2017).

⁴⁷ The Colorado River Basin Salinity Control Act was also passed in 1974 to address the issue of high salinity levels of water delivered to Mexico. This act did not impact dam operations on the Colorado River. However, according to the act, 25 percent of the total costs of constructing, operating, maintaining, and replacing salinity control units are allocated between the Upper Colorado River Basin Fund and the Lower Colorado River Development Fund.

Starting 1995, Interior entered into a number of agreements with state-level agencies to develop the Lower Colorado River Multi-Species Conservation Program; Interior along with USFWS also began conducting studies as part of NEPA 1969 compliance requirements for the development and implementation of the LCR MSCP. After the Final Environmental Impact Statement was published in 2004, Secretary of the Interior to signed the Record of Decision for the LCR MSCP in 2005 (Interior, 2005), which will remain effective until 2055. LCR MSCP's purpose is to:

- a. Conserve habitat and work towards the recovery of threatened and endangered species, as well as *reduce the likelihood of additional species being listed*
- b. *Accommodate present water diversions and power production and optimize opportunities for future water and power development*, to the extent consistent with law, and
- c. Provide the basis for incidental take authorizations (Interior, 2005, emphasis added)

LCR MSCP is thus a unique program, in that—a) it does not jeopardize dam operations for water delivery or power generation, b) it proactively protects 26 species to prevent future listing of these species as endangered, and c) it provides coverage to both Federal and non-federal interests under sections 7 and 10 of the ESA respectively (LCR MSCP, 2017). As most activities under LCR MSCP require either protection of existing/creation of new habitat or fish recovery/augmentation⁴⁸, they do not constrain the timing or amount of water that is released through Hoover Dam. The LCR MSCP is funded through the Lower Colorado River Basin Development Fund, wherein, a part of the revenue for the fund is derived from a surcharge on actual amount of electricity sold from Hoover dam to users in Arizona, California, and Nevada.

Glen Canyon Dam

Since its construction, the operation of Glen Canyon Dam for generating peaking power during periods of high electricity demand had resulted in fluctuating releases of water on a daily timescale. These wide fluctuations eliminated the river's natural flow variability and associated sediment transportation downstream. Such flow alterations had raised concerns about its detrimental effects on downstream resources, specifically those in the Grand Canyon (GAO, 1996). Consequently, in July 1989, the Secretary of the Interior directed the Bureau of Reclamation to prepare an Environmental Impact Statement to assess feasibility of alternative options for operating the dam, such that impacts on “downstream environmental and recreational resources, as well as on Native American interests” could be minimized, while at the same time hydropower generation could be maintained (GAO, 1996, p. 2).

The Grand Canyon Protection Act of 1992 required the Reclamation to complete this environmental impact statement by 1994, which was ultimately completed in March 1995

⁴⁸ i.e. raising endangered fish in hatcheries

(Interior, 1996). The alternatives considered in the Final Environmental Impact Statement varied with respect to monthly, daily, and hourly release fluctuations from Glen Canyon Dam, but did not change the annual releases (Interior, 1996). The alternative that was ultimately selected through the 1996 Record of Decision (RoD), and remained in effect until 2016, was the Modified Low Fluctuating Flow criteria. Modified Low Fluctuating Flow restricted daily and hourly operations of Glen Canyon compared to other alternatives. The Modified Low Fluctuating Flow criteria also included beach/habitat-building flows; however, to minimize impact on power generation, these beach/habitat-building flows were scheduled for years where excess water releases were available in Lake Powell (Interior, 1996). In addition, the RoD also established the Glen Canyon Adaptive Management Program (implemented by the Adaptive Management Workgroup), to assess the performance of extant operating criteria, and make modifications according to scientific findings (Interior, 1996). As a result, a number of experimental releases were also carried out between 1996 and 2016 (see for example, Reclamation, 2008), which significantly affected hydropower operations at Glen Canyon Dam.

To guide dam operations after the 1996 RoD was set to expire, Interior passed the Long-Term Experimental and Management Plan (LTEMP) through the 2016 RoD (Interior, 2016). The LTEMP will remain in effect until 2036. LTEMP maintains the same constraints for daily water releases for hydropower operations.

2.2.3 Energy Laws and Policies

Collective-choice level institutional arrangements pertaining to energy govern marketing and allocation of power from Hoover and Glen Canyon Dams and create the framework within which electric service contracts are developed. For the two dams, collective-choice level arrangements either build on or limit the applicability of constitutional-choice level institutional arrangements; this in turn produces differences in power contracts that are signed with prospective customers for Hoover and Glen Canyon Dams. Consequently, the collective-choice level institutional arrangements and their implications for power marketing, allocation, and specific electric service contract elements—contract duration, rates, and/or provisions governing customers’ use of their hydropower allocation⁴⁹—will be discussed for each dam separately.

Hoover Dam

The debate over allocation of power from Hoover Dam predates not only the Boulder Canyon Project Act of 1928 (the act that authorized the construction of Hoover Dam), but also the Colorado River Compact of 1922—the bedrock of the Law of the River. This debate

⁴⁹ Power contracts are legal documents that outline the responsibilities, obligations, and rights of WAPA and the power customer. As such, contracts cover a range of provisions regarding the terms of delivery of hydropower, terms of use of this power, payment of bills etc. This discussion has only focused on three elements—contract duration, rates, and provisions governing customers’ use of their hydropower allocation—as these three elements directly influence how customers can use this resource and the reasons why customers value this resource.

primarily involved municipal⁵⁰ and private interests⁵¹ and revolved around questions such as who should build and receive power from the proposed Hoover Dam (then called Boulder Dam) (Hundley, 2009)⁵². The pattern of power allocation that we observe today has its roots in this debate.

When Boulder Canyon Project Act was passed in 1928, the Secretary of the Interior was granted the power to frame and sign contracts for the storage and delivery of water, “for irrigation and domestic uses, and generation of electrical energy and delivery... to States, municipal corporations, political subdivisions, and private corporations of electrical energy” (Section 5). Further, Section 5 (a) set the maximum duration of power contracts between the Secretary and power customers at 50 years, with the provision of readjusting the same every ten years. Once the authority for contracting power and the duration of contracts was established, the next logical step was to figure out how the Secretary would identify suitable customers and resolve issues with competing applications for power, a topic of great import in the debate over allocation of Hoover power.

To this end, Section 5 (c) provided a complex response. It stated, “[c]ontracts...for the generation and distribution of hydroelectric energy or for sale and delivery of electrical energy shall be made with *responsible applications therefore who will pay the price fixed by the said Secretary* with a view to meeting the revenue requirements herein provided for. In case of conflicting applications, if any, such *conflicts shall be resolved* by the said Secretary, after hearing, *with due regard to the public interest*, and in *conformity with the policy expressed in the Federal water power act...except that preference to applicants...*for the generation and distribution of hydroelectric energy, or for delivery at the switchboard of a hydroelectric plant, *shall be given, first, to a State for the generation or purchase of electric energy for use in the State, and the States of Arizona, California, and Nevada shall be given equal opportunity as such applicants*” (emphasis added). The contracts provision under Section 5(c) generated a host of questions as it laid out various guidelines (see emphasis above) for the selection of applicants — what did Congress mean by public interest? did public interest trump preference rights or vice versa? could States claim double preference rights under the Federal Water Power Act and the BCPA to strengthen their applications over other customers? did States now have preference over municipalities even outside the context of BCPA? As there were bound to be conflicting offers, these questions were central in determining the first and each subsequent process for marketing Hoover power.

The Secretary of the Interior requested Department of Interior’s Solicitor to prepare a memorandum to shed light on questions regarding the interpretation of various provisions within

⁵⁰ This was the Los Angeles Department of Water and Power

⁵¹ Especially the Southern Sierras Power Company and the Southern California Edison Company

⁵² Historian Norris Hundley Jr.’s famous book ‘Water and the West’ includes a chapter titled ‘Power Sets the Stage’ (pp. 110-137 in the 2009 Edition) that recounts this debate in greater detail.

the BCPA, majority of which related to Section 5 on power marketing. In response, Solicitor Finney published his opinion a memorandum in 1930 that went on to clarify the provision as follows. The term public interest, as it appeared in Section 5(c) of the BCPA and in the referenced Federal Water Power Act (Section 7 specifically) referred to “the Government’s responsibility, financial and otherwise, to all the people of the United States...[consequently][t]he term ‘public interest’ is the dominant consideration, a check upon the preferences mentioned in the two acts (i.e. BCPA and FWPA)...the ‘public interest’ is in the soundness of the contracts and the solvency of the contractor, not in the corporate or municipal character of that contractor” (p. 5). By defining public interest in financial terms and by giving a customer’s financial solvency a higher priority than the preference clause, Solicitor Finney opened up the doors to marketing Hoover power to private interests⁵³.

Solicitor Finney’s opinion further clarified the preference clause as it applied to States. While Section 5 (c) of BCPA and Section 7 of FWPA gave preference to States, the importance of the preference language in BCPA lay in the distinction between States and municipalities. For BCPA this distinction was of utmost importance as it preserved the rights of the three preference States over municipalities. What this meant was that the rights of Arizona and Nevada were superior to those of Los Angeles, i.e. the Los Angeles Department of Water and Power that had gained notoriety in the day⁵⁴. But this preference of States over municipalities ended there, i.e. States could not claim preference over municipalities unless it pertained to marketing of Hoover power. Moreover, only Arizona, Nevada, and California could claim such a preference. In case a State other than the three preference States and a municipality of another state presented applications to the Secretary of the Interior, the Secretary could use the “broad discretionary power” vested in him/her by the guiding principle of public interest to make an allocation as he deemed fit between the two parties (Solicitor Finney, 1930, p. 5).

⁵³ Historian William D. Rowley writes that from the early stages of negotiation of the BCPA, the forces of private power worked to ensure that they would not have to face what they considered as “unfair competition” from the government (i.e. public power). The fact that private power interests were built into the BCPA—and the resultant blending of public and private enterprise— were a necessity given the political realities of the 1920s. As Hundley (2009) notes, “[n]ot everyone wanted either Los Angeles or private power interests to gain a foothold in Boulder Canyon, but to many there seemed to be no way of keeping them out” (p. 118). Rowley notes that those who advocated for a larger role for the federal government in the production and distribution of power did not hold sway in either the House or the Senate in the 1920s, which was the decade of pro-business Republican ascendancy (2006, p. 287). The inclusion of private power interests in BCPA, meant that in the ongoing public versus private power debate, “Hoover Dam was not a victory for public power” (2006, p. 287).

⁵⁴ In the debate and dispute over power allocation from Hoover (Boulder) Dam, Californians preferred private power interests to the city of Los Angeles, i.e. the Los Angeles Department of Water and Power (LADWP), as they distrusted the city after the Owens valley water rights incident. Joining Californians in their suspicion of Los Angeles were leaders in Arizona and Nevada as they distrusted the city and were resentful of Arthur Powell Davis’ presumed preferential consideration of LADWP in the allocation of Hoover power (see Hundley, 2009, pp. 113–124). Against this backdrop of distrust and suspicion against LADWP, the BCPA preference clause was worded in a way that ensured that States would receive preference over LADWP.

Following the publication of Solicitor Finney’s memorandum, the initial power allocations were made in 1930 to 9 entities: Metropolitan Water District of Southern California (MWD), Cities of Los Angeles, Glendale, Pasadena and Burbank in California, Southern California Edison Company, Arizona Power Authority (representing Arizona), Colorado River Commission of Nevada (representing Nevada), and City of Boulder City, Nevada. These contracts became effective in June 1937 after Hoover began generating power.

BCPA’s provisions regarding contracting reflected the outcome of the political debate over power allocation from Hoover in the years prior. BCPA, specifically Section 5 of the act, remains the fundamental basis for allocating power and formulating the basic terms of power contracts even today.

When the Reclamation Project Act was passed in 1939 the allocation of Hoover power had already been completed. Section 9(c) of the Reclamation Project Act had laid out a 40-year contract term for power contracts as well as explicit preference for municipalities and public agencies (see Section 2.1.3.2). These provisions threatened the 50-year contract term as well as the possibility for private power interests to contract for power from Hoover Dam in the future. To prevent such an eventuality, the applicability of this constitutional-choice level law was limited by introducing a section in the Reclamation Project Act that explicitly stated that it would not amend BCPA (Section 18).

When power contracts were first signed for Hoover, they were designed such that power was to be sold at market rates (MWD, 2016). Market rates for Hoover power, however, turned out to be higher than expected as electricity could be bought at a cheaper cost from steam power plants (MWD, 2016). The Boulder Canyon Project Adjustment Act was therefore passed in 1940 to remedy this situation; henceforth, electricity was to be sold ‘at cost’ i.e. costs that were sufficient enough to cover only construction, operation, and maintenance of the dam (Section 618), and not to recover a profit.

As the 1937 contracts were set to expire in 1987, Congress passed the Hoover Power Plant Act (HPPA) in 1984 to address various matters related to power generation and marketing at Hoover Dam. This act authorized the Secretary of the Interior to “increase the capacity of existing generating equipment” at Hoover power plant—called the ‘uprating program’— and create visitor facilities (Hoover Power Plant Act, 1984, Section 101(a)). The uprating program resulted in the addition of 500 MW of power generating capacity at Hoover (MWD, 2016). By the time this act was passed, power marketing functions had been transferred from the Secretary of the Interior to the Secretary of Energy under Department of Energy Organization Act of 1977. This change in responsibility was reflected in HPPA 1984 as the Secretary of Energy—acting through WAPA—now had the authority to frame contracts for the sale of Hoover power.

HPPA 1984 reduced the power contract term from 50 years to 30 years and created various schedules of power and associated contractors/customers for the allocation of ‘contingent capacity’ and ‘associated firm energy’ (Section 105). In accordance with Section 105 (A), the 9 original power contractors that received an allocation of Hoover power were categorized as ‘Schedule A’ contractors. The additional power generated through the uprating program was contracted as ‘Schedule B’ as per Section 105 (B). Schedule B contractors were those that advanced the funds required for the uprating program, namely, cities of Glendale, Pasadena, Burbank, Anaheim, Azusa, Banning, Colton, Riverside, and Vernon in California, Arizona Power Authority and the Colorado River Commission of Nevada (MWD, 2016). In case power generation exceeded 4501.001 million kilowatt hours in any year starting 1987, the contracts were signed under ‘Schedule C’, with first preference given to Arizona. After the passage of HPPA 1984 the total number of power customers increased from 9 to 15 and the overall state-wise power allocation was roughly 56%, 25% and 19% for California, Nevada and Arizona respectively.

For the first time in the history of Hoover power allocation and marketing, HPPA 1984 also clarified how reduction in power generation at Hoover Dam would be distributed. Although the new contracts were signed as contingent capacity and associated firm energy contracts—i.e. contractors would receive firm energy that could be generated with the available capacity based on hydrological and technical constraints—that limited WAPA’s energy delivery obligation to customers, it was nonetheless assumed that 4527.001 million kilowatt hours of energy could be generated each year. If there was a shortfall in energy generation, Schedule A and B contractors⁵⁵ were to face power cuts in “the ratio that the sum of the quantities of firm energy to which each contractor is entitled pursuant to said schedules bears to 4527.001 million kilowatt hours” pursuant to Section 105 (2) of HPPA 1984. However, in case of such cuts, Section 105 (2) created the provision of purchase of power in the energy market by the Secretary of Energy to meet the deficiency in the power supplied to any given contractor at the contractor’s expense. From the standpoint of operational level rules HPPA 1984 is important as it created a rule of proportionality in bearing power cuts by all the power customers in case of poor hydrological conditions.

In the 30-year period since Hoover power contracts were renewed in 1987, a lot had changed in the electricity sector and Colorado River Basin hydrology. On the electricity sector side, competitive wholesale markets had gained a stronghold in the Western U. S. and California ISO (established in 1998) was a major entity that facilitated such market transactions. On the hydrology side, the Basin entered one of the worst droughts in instrumental records in 2000. These changes propelled existing Hoover power customers to initiate discussions in 2008 on post 2017 power marketing. Some of the pressing questions in these early discussions included who would allocate Hoover power after 2017, how much power was to be allocated and would

⁵⁵ The term contractor and customer has been used interchangeably in this paper

WAPA withhold certain capacity, what would be the contract duration, and what would be its terms given the rapid changes in the electricity sector (Pongcraz, 2016). Some of the key demands of the existing customers were—(i) maintain their extant allocations post 2017, (ii) extend the current contract term from 30 to 50 years, (iii) allow contractors to use their Hoover allocation in RTOs/ISOs, (iv) preserve the ancillary service benefits of Hoover power, and (v) allow customers to terminate their contract if the hydrology or economics made Hoover power an unsuitable option for the contractors’ portfolio (Interview with staff at WAPA, 2018). The last demand became extremely politically contentious; customers wanted stability and flexibility in their contracts yet they were unwilling to accept the risk that came with a changing hydrology (Interview with staff at WAPA, 2018).

The discussions ultimately resulted in the passage of a Congressional legislation in 2011 that represented a compromise between existing power interests and the government. Obama signed the Hoover Power Plant Act in 2011 (HPPA 2011) which met most of the demands of the existing customers in exchange for a slight reduction—to be precise 5 percent—in their extant allocations that could be used to extend the benefit of Hoover power to new customers in the spirit of promoting “widespread use” (Interview with staff at WAPA, 2018). This resource pool “equal to 5 percent of the full rated capacity of 2,074,000 kilowatts, and associated firm energy” was to be allocated to ‘new customers’ that had never received power under Schedule A or B of HPPA 1984 (Hoover Power Allocation Act, 2011, Section 2 (d)). Part of the Schedule D power was allocated by WAPA directly and part of it was allocated by the Arizona Power Authority and Colorado River Commission for new customers in Arizona and Nevada respectively. The end result was the increase in total customers from 15 starting 1987 to 46 starting 2017. 23 of the 31 new customers were Native Tribes that had never received an allocation for Hoover power (WAPA, 2017c).

HPPA 2011 made other pertinent changes to contract terms that remarkably enhanced the resource value of Hoover power for its customers. One, it extended the contract duration from 30 to 50 years (Section 2 (g)). Two, it modified the resale prohibition provision⁵⁶ in old contracts and permitted transactions with an independent system operator (Section 2 (g)). Three, it safeguarded the ancillary service benefits of the Hoover power allocation (Section 2 (g)). Four, when a customer failed to accept the contract offered to it, the act outlined a process for re-allocating this power in a manner that gave preference to existing customers; preference for unclaimed power was to be first made available to entities within the same Schedule list (with preference given to a State over other entities as in BCPA 1928) followed by entities that receive Schedule D power (with preference provisions remaining the same as in BCPA 1928).

⁵⁶ According to the resale prohibition provision, a customer that received Hoover power could not any sell this energy to anyone but its end-users.

With the ongoing drought, HPPA 2011 also introduced a section on power delivery in relation to availability of water. Section 2 (j) of the act limited WAPA's obligation to deliver contingent capacity and associated firm energy to customers to such quantities as could be provided given the availability of water. The act slightly modified the provision for distributing power cuts that was first introduced in HPPA 1984 to capture the new schedule of power customers, i.e. Schedule D. Section 2 (j) specified that in the event water was not available to produce the contingent capacity and firm energy contracted for under Schedules A, B, and D, then the Secretary of Energy had the authority to adjust the allocations in the same proportion as each customer's share of contingent capacity and firm energy to the full rated contingent capacity and firm energy obligations.

Glen Canyon Dam

Unlike Hoover Dam, where collective-choice level laws predominantly dictate power marketing, allocation, and contracts, the power generated at Glen Canyon Dam is marketed, allocated, and contracted for in accordance with *both* constitutional and collective-choice level laws. While Hoover power is allocated by itself, Glen Canyon power is allocated as a part of the overall Colorado River Storage Project that additionally includes three small hydropower generating units. Moreover, while Hoover power is primarily allocated through legislative action, such as the HPPA 1984 or HPPA 2011, Glen Canyon power is marketed and allocated through administrative rulemaking. WAPA develops marketing criteria and plans following a typical notice and comment procedure to guide its power marketing and allocation activities. Marketing criteria and plans (hereafter marketing plans) commonly address issues such as contract terms and conditions, the geographic area where electricity will be sold, the amount of electricity offered, who is eligible to receive the electricity, how power is allocated among applicants, and the deadline for successful applicants to sign their contracts (WAPA, 2016a).

WAPA's marketing plans, and by extension power contracts for the Colorado River Storage Project (CRSP) facilities are based on the provisions contained in three foundational laws. At the collective-choice level, the Colorado River Storage Project Act of 1956 is the most important piece of legislation that undergirds WAPA's marketing plans with respect to hydropower generation at Glen Canyon Dam. Per Section 7 of this act, the Secretary of the Interior, and WAPA⁵⁷, are required to market the power generated at CRSP facilities under long-term *firm* power contracts. Firm power contracts are markedly different than *contingent* power contracts used in the case of Hoover; firm contracts obligate WAPA to deliver the contractor's allocated share of power regardless of hydropower generating conditions. That is, if there is inadequate hydropower available due to a drought or operational constraints, WAPA must purchase power from the open market, from other utilities, or IPPs to meet its firm power obligation (WAPA, 2016a). In addition to the firm power contract provision, WAPA's marketing

⁵⁷ As WAPA assumed Reclamation's responsibilities over power marketing in 1977

plans and power contracts have to abide by two constitutional-choice level provisions: Section 9(c) of Reclamation Project Act of 1939 and Section 5 of Flood Control Act of 1944. According to Section 9(c) of Reclamation Project Act of 1939, WAPA is required to market power generated at CRSP facilities to preference customers and can sign contracts for a maximum duration of 40 years; Section 9(c) of the Reclamation Project Act does not apply to Hoover power contracts. WAPA is also required to market power to ensure ‘the most widespread use... at the lowest possible rates to customers’, provided that such rates provide sufficient revenue to cover construction, operation, maintenance, and fixed costs (Section 5 of the Flood Control Act of 1944 and Section 9(c) of Reclamation Project Act of 1939). Taken together, it is provisions contained in the three foundational laws—CRSP 1956, Reclamation Project Act of 1939, and Flood Control Act of 1944—that cause CRSP power contracts and the number and types of entities that receive power from CRSP facilities to differ profoundly from Hoover power contracts and power customers.

Within the framework created by the three foundational laws, WAPA’s marketing plans and power contracts have evolved over the years to reflect changes in the pattern of energy demand and hydrology in the Basin, changes in the broader electricity sector, and constraints posed on hydropower generation by environmental water needs. Beginning with the first marketing plan passed in early 1960s, the subsequent paragraphs trace the changes in marketing plans and power contracts over time.

In 1960, Secretary of the Interior Fred A. Seaton announced the first criteria that would guide the marketing of power from the Colorado River Storage Project⁵⁸(Congressional Record Vol. 106 Part 9, 1960, p. 11466). The criteria identified the geographic marketing area for the sale of power from the CRSP units: the northern division consisting of States of Colorado, New Mexico, Utah, and Wyoming, and, southern division consisting of States of Arizona, along with parts of Nevada and California⁵⁹. Only those preference customers that were a part of either division could apply to the Secretary for a power allocation.

When the 1960 criteria were announced, it was clear that energy demand in the northern division had not yet developed compared to its southern counterpart (see for example basic

⁵⁸ According to a recent presentation by WAPA staff, the first power marketing criteria were supposedly announced on March 9, 1962. On reviewing the federal register for that day, any notices (either proposed or final) on such marketing criteria could not be found. An older Congressional Record of the Proceedings and Debates of the 86th Congress (Senate) from May 31st 1960 on “Conservation of Utah’s Water Resources” does however include an exhibit titled “Colorado River Storage Project Power Marketing Area and Criteria Announced”. This exhibit includes provisions that appear to be similar to the ones identified under the 1962 Marketing Criteria by the WAPA staff (see Mullen & Wicks, 2015). It is unclear whether the 1962 criteria were substantively different than the ones that appear in the 1960 Congressional Record; consequently, for this paper only the 1960 criteria have been used as they could be reviewed first hand.

⁵⁹ Specifically, the parts of Nevada included Clark, Lincoln, and Nye counties which comprise the southern portion of the state and in case of California the part of the State east of the 115th degree of longitude or generally the area contiguous to the Colorado River was included in the marketing area.

principle 3, 4 in Congressional Record Vol. 106 Part 9, 1960, p. 11466). Consequently, the criteria included specific provisions for recapture of firm power and energy made available to existing customers, including contractual commitments made to the southern division, to meet the future needs of the northern division⁶⁰. Secretary Seaton argued that the marketing of power in the southern division with the safeguard of withdrawal when needed to meet the growing electricity demands in the northern division would be economically advantageous given the diversity in peak loads between the two areas and would enable the Government to market a “great amount” of Glen Canyon firm power (Congressional Record Vol. 106 Part 9, 1960, p. 11466).

The 1960 marketing criteria also laid down the resale prohibition principle that would apply to all future CRSP power contracts. Under the resale prohibition principle, power from the CRSP project could not be sold to a preference customer for sale or exchange in turn to a non-preference customer for resale (Principle 5). Simply put, non-preference customers, such as IOUs, could not buy or exchange the power allocated to preference customers. The intent of the resale prohibition was to ensure that end users served by preference customers would receive the benefit of low-cost hydropower and that this power was not sold to make a profit. From an operational standpoint, the resale prohibition principle is extremely important as it determines the ability of a customer to not only resell power to non-preference customers but also use their allocation of CRSP hydropower in energy markets. The resale prohibition continues form a part of power contracts with certain modifications⁶¹ that reflect changes in the electricity industry. Lastly, the 1960 criteria established a seasonal—summer and winter—power allocation schedule for CRSP resources (Mullen & Wicks, 2015).

With the creation of WAPA in 1977 and the expansion of southwest regional electricity needs, WAPA determined that there was a need to modify the existing power marketing plan of 1960/1962 (Wegner, 1988, p. 386). To this end, WAPA made one change each to the then existing marketing plan and power contracts in 1978⁶². First, the 1978 marketing plan refined and expanded the marketing area for the northern division to incorporate Page and areas served by the Navajo Tribal Utility Authority in Arizona, and White Pine County along with portions of Elko and Eureka Countries in Nevada (Mullen & Wicks, 2015). There were no changes made to the southern division. Second, WAPA extended the termination date of the original power contracts to September 1989 (Wegner, 1988, p. 386).

⁶⁰ The criteria noted that initiation of construction of transmission lines into the southern division would not occur until “specific assurances [were] obtained from prospective customers in the southern division that the principle of recapture set out above will be applicable to allotments to, and contracts for, the sale of power to such customers” (Principle 4(c) in Congressional Record Vol. 106 Part 9, 1960, p. 11466).

⁶¹ The modifications are discussed on p. 52.

⁶² The 1978 modifications could not be reviewed first hand as they are not available publicly. Two disparate sources—Mullen and Wicks, 2015; Wegner, 1988—however refer to the same modification; consequently, these two sources were used to discuss the modifications.

Even as WAPA made changes to the marketing plan and power contracts in 1978 that were not set to expire until 1989, WAPA recognized the need to start early on the Post-1989 marketing plan for a variety of reasons. Notable among them were that good hydrology made available an additional 55 MW of capacity in both winter and summer seasons that could be allocated to either existing or new customers, and that poor repayment performance of some non-CRSP irrigation projects in the Upper Basin would require WAPA to integrate these resources with CRSP facilities for marketing purposes (Federal Register Vol. 51 No. 26, 1986; Mullen & Wicks, 2015). These reasons were politically contentious. On the one hand, the availability of additional resources pried open old debates on who could receive an allocation from CRSP facilities and the applicability of the concept of ‘preference customers’ in power marketing. On the other hand, the integration of non-CRSP resources in marketing CRSP power brought to light the issue of whether CRSP power contracts should subsidize poor-performing irrigation projects beyond those authorized by CRSP 1956. Consequently, the design of the Post-1989 marketing plan began in 1980.

WAPA received and considered about 1500 written comments in the development of the Post-1989 marketing plan and contract terms⁶³. As WAPA anticipated, these written comments raised a host of issues pertinent to the marketing plan, specifically on questions of who should receive an allocation of Federal hydropower as well as the geographic extent of the marketing area, and contract terms, specifically the length of the contract itself (Federal Register Vol. 51 No. 26, 1986). The issues raised in the written comments pertaining to who should receive an allocation of CRSP hydropower are worth recounting for at least two reasons. One, they show how existing and prospective customers—public and private entities—in both northern and southern divisions fought fiercely to either protect their allocation or receive an allocation of CRSP hydropower, which in turn reflects the importance of this resource to the customers. Two, the process of developing the Post-1989 marketing plan was the last time in the history of CRSP power allocation and marketing that the public versus private debate received center stage. The subsequent paragraphs therefore briefly discuss the issue of power allocation as it appeared in process of developing the final Post-1989 marketing plan.

On the topic of allocating power to public or private entities, IOUs argued that WAPA could not limit preference power marketing to only those entities that received a mention in the Reclamation Project Act of 1939, and Flood Control Act of 1944. The basis for this argument was two-fold: WAPA was mandated under the Department of Energy Organization Act of 1977 to also utilize the “productive capacity of private enterprise” in the development and achievement of policies and purposes, and given changes in the electric power industry the concept that preference laws promote yardstick competition was “an anachronism” (Federal Register Vol. 51 No. 26, 1986, p.4846–4847). On the flipside, public power advocates

⁶³ By comparison, WAPA received just 18 written comments in the process of developing the most recent marketing plan i.e. Post-2025 marketing plan.

highlighted the importance of both the preference law as well as CRSP hydropower in their arguments for extending the duration of existing power contracts from 10 years to 20 years. For municipalities and rural cooperatives, CRSP hydropower served as a low-cost resource base that was important in attracting new industries and businesses to small towns and rural areas; longer contract terms provided stability and reduced the uncertainty of preference users' power supply (Federal Register Vol. 51 No. 26, 1986, p.4846). Municipalities also argued that longer term contracts would minimize the opportunities available to IOUs to challenge the existing preference laws. On the public versus private debate, WAPA rejected IOUs' argument on grounds that it had flexibility in carrying out its functions laid out in the Department of Energy Organization Act of 1977 and that it was "legally bound" to uphold the preference law whether or not IOUs found it anachronistic (Federal Register Vol. 51 No. 26, 1986, p.4846, p. 4847). Consequently, in the Post-1989 marketing criteria, WAPA held on to the preference criteria laid out in the Reclamation Project Act of 1939 and Flood Control Act of 1944 in allocating CRSP hydropower. IOUs have since been unable to change this marketing criteria to their benefit.

On the issue of allocation based on the geographic location, the northern division customers argued that it was inappropriate for WAPA to market hydroelectric resources physically located in the northern division outside of the division, whereas, southern division customers argued that the allocations to southern division were intended to be permanent (even though this was not the case given the recapture provision in the 1960/62 marketing plan). The northern division versus southern division allocation issue became an important "divisive issue" in the Post-1989 marketing process (Federal Register Vol. 51 No. 26, 1986, p.4850). To assuage the two sides, WAPA adopted an approach where it recognized and renewed the existing allocations of the southern division customers, but reserved the additional capacity that became available for only northern division customers (Federal Register Vol. 51 No. 26, 1986). Moreover, it removed California from its southern division geographic area and preserved the right to restrict future marketing to only the northern division if necessary (Federal Register Vol. 51 No. 26, 1986).

WAPA published the final Post-1989 marketing plan in 1987. In this plan WAPA— i) maintained the power allocations made to southern division customers prior to 1989, ii) increased the capacity offered to northern division customers, iii) provided power contracts to additional customers in the northern division, iv) increased the contract duration from 10 years to 15 years to strike a balance between *retaining flexibility* in responding to changes in the marketable resources due to changing hydrological conditions and *providing stability* to preference customers in using their allocation, v) set a limit of 400 GWh of energy that it will purchase to meet its firm energy obligations, vi) allowed annual exchanges of capacity between customers without division restrictions to allow customers to use their allocations to their best advantage, vii) integrated Colbran and Rio Grande projects with CRSP projects—together called

Salt Lake City Area Integrated Projects (hereafter SCLA/IP)—for marketing and rate-setting purposes⁶⁴ (Federal Register Vol. 51 No. 26, 1986; Federal Register Vol. 52 No. 63, 1987).

As the final Post-1989 marketing plan was published, the National Wildlife Federation (NWF) and several other environmental groups filed a lawsuit against WAPA⁶⁵ claiming that WAPA had violated NEPA 1969 by failing to prepare an environmental impact statement on the Post-1989 marketing criteria. In early 1989, WAPA sought permission from Judge Greene to execute its Post-1989 power contracts for SLCA/IP (Committee on Power Marketing Agencies, 1990). While NWF opposed the execution of contracts, Judge Greene approved the execution of contract and a permitted a “reopener” clause allowing WAPA to modify contract power allocations (Committee on Power Marketing Agencies, 1990). In September 1989 WAPA announced that it would prepare an EIS on the Post-1989 marketing criteria. In November 1989, WAPA prepared an interim marketing plan with all the same provisions as the final Post-1989 marketing plan except with an additional feature that it, i.e. WAPA, had the right to revise the Post-1989 power contracts based on decisions arising out of WAPA’s EIS, or on decisions arising from the ongoing EIS on Glen Canyon Dam that assessed the environmental and downstream effects of peaking operations at the Dam or recovery implementation programs for endangered species (Committee on Power Marketing Agencies, 1990). The Court approved this marketing plan along with contracts that became effective on December 1, 1989 (Committee on Power Marketing Agencies, 1990).

After the Court approved WAPA’s interim marketing plan, WAPA began the power marketing EIS, which studied a range of commitment level alternatives for the SLCA/IP based on their economic and natural resource effects. The EIS identified the Post-1989 firm power commitment levels of 1449 MW capacity and 6,156,000 MWh of energy as the preferred alternative. WAPA’s Administrator signed a Record of Decision on October 17, 1996 to set these as the commitment level for its wholesale firm-power contracts which were signed in 1989 and set to expire in 2004 (WAPA, 1997, Chapter 2, p. 11). WAPA amended power contracts with individual customers to reflect the changes in firm commitment levels and called the revised commitment the contract rate of delivery (CROD). The CROD “is the maximum amount of

⁶⁴ With regards project integration, WAPA argued that Colbran and Rio Grande Projects had had problems in meeting repayment obligations and maintaining marketable rates (Federal Register Vol. 51 No. 26, 1986, p. 4851). Consequently, integration these two projects with CRSP projects would assure the United States government that the costs of these projects would be repaid. While CRSP customers raised concerns with such ‘subsidization’, WAPA argued that it would have purchased power anyway from Colbran and Rio Grande project to meet CRSP firm power obligations, and thus, integrating projects was not in fact a subsidy but a federal mandate. Project integration, in WAPA’s opinion, had other benefits for CRSP customers; the single rate adjustment process as well as the simplification of contract administration due to project integration would reduce administrative costs, and integrating projects would reduce the need for each individual project to maintain project reserves thereby making additional firm power available for customers.

⁶⁵ National Wildlife Federation v. Western Area Power Admin., No. 88-C-1175-J (1988)

capacity with firm transmission that can be scheduled by the SLCA/IP customer each season through the contract period” (WAPA, 1997, Chapter. 2, p. 16).

In 1992, when Congress passed the Grand Canyon Protection Act (GCPA 1992), it recognized that any changes in long-term operational criteria for Glen Canyon Dam that came out of the findings of the ongoing EIS could impact power generation. To this end, GCPA 1992 directed the Secretary of Energy to “identify economically and technically feasible methods of replacing any power generation that is lost” due to adoption of such criteria (Section 1809). Identifying mechanisms to replace lost power was important especially since WAPA had a *firm* obligation to power customers and a reduction in power generation could have increased the purchase power costs borne by customers. Consequently, WAPA and a group of SLCA/IP firm-power customer representatives began working together to develop alternatives to replace the loss in power generation at Glen Canyon after the Secretary of the Interior adopted the Modified Low Fluctuating Flow criteria in 1996. The outcome of this process resulted in amended contracts that established a “prudent long-term commitment level of sustainable hydropower (SHP)⁶⁶” as well as the creation of two programs: Western Replacement Power (WRP) and Customer Displacement Power (CDP) programs⁶⁷ (WAPA, 1997, Chapter 2, p. 15). In addition, the contract amendment discussed above included the concept of available hydropower (AHP) to represent the actual amount of hydropower that will be available to each customer for the upcoming summer or winter seasons.

In the context of CROD and SHP, AHP works as follows—each season, SHP and CROD determine the contractual floor and ceiling respectively of the firm capacity allocation to the individual customers; level of AHP can vary between this floor and ceiling. WRP and CDP are then used to meet the shortfall between the AHP and the CROD. With the modification of contracts, WAPA’s purchase power obligation was limited to satisfying only the SHP allocation. This in turn brought about a change in the calculation of firm power rates for customers as the ‘socialized’ part of SLCA/IP firm power rates, i.e. rates that have to be paid by *all* customers to purchase additional power, was limited to WAPA’s SHP obligation. Costs of replacement power beyond the SHP, either in the form of WRP or CDP, is borne by customers themselves. This contract modification was important as it created additional flexibility for customers, from an economic standpoint, to respond to changes in power generation at Glen Canyon Dam.

The Post-1989 marketing plan and contracts, along with its amendments that created CROD, SHP, AHP, WRP, and CDP, are important as they continue to serve as the basis for all current and future marketing plans and contracts.

⁶⁶ SHP is the minimum aggregate level of long-term firm capacity and energy that is provided to all SLCA/IP customers through the contract period.

⁶⁷ Western Replacement Power (WRP) is the power that is purchased on behalf of individual customers by WAPA to make up for any shortfall in SLCA/IP power generation. Customer Displacement Power (CDP) on the other hand is procured by customers.

As the 1989 contracts were set to expire in 2004, WAPA published the final allocation of the Post-2004 resource pool for SCLA/IP in 2002 (Federal Register Vol. 67 No. 23, 2002). This plan reduced the existing customers' pro rata share of SCLA/IP allocation by 7 percent, i.e. it maintained 93 percent of the allocation, and extended the 1989 contracts for 20 years until September 2024. The power pool created by withholding 7 percent of the then existing customers' allocation was offered to new customers in SLCA/IP marketing area. This entire power pool was allocated to Native Tribes (Federal Register Vol. 67 No. 23, 2002, p. 5115). While there were approximately 119 customers that received SLCA/IP allocation in the Post-1989 contracting period, this number increased to approximately 130 in the Post-2004 contracting period. Of the 130 long-term firm power customers, 53 customers are Native Tribes, 60 customers are municipalities, cooperatives and irrigation districts, and 17 are other organizations including governmental agencies and public bodies such as universities (Jeka, 2013).

When the final Post-2004 marketing criteria was published, it included a provision that allowed WAPA to adjust all power allocations if there was a change in the amount of marketable resources due to hydrological constraints (Federal Register Vol. 67 No. 23, 2002, p. 5116). In 2004, WAPA revised the total energy allocation for the 2004-2024 contract period due to the severe drought conditions in the Upper Basin (Federal Register Vol. 69 No. 98, 2004). It maintained the same CROD levels as the Post-1989 level but reduced the energy component from 6,156,000 MWh to 4,557,500 MWh for 2005. Beginning 2005, the amount of marketable energy was to increase each year until it reached a plateau in 2009 at 4,948, 800 MWh (Federal Register Vol. 69 No. 98, 2004).

The Post-2004 contracts are in effect at present. However, WAPA has already published the final Post-2025 marketing plan and is currently negotiating final contracts with customers. In the final Post-2025 marketing plan, WAPA has agreed to extend the Post-1989 CROD and associated seasonal energy allocation to all existing (i.e. Post-2004) customers (Federal Register Vol. 81, No. 229, 2016). The final Post-2025 marketing plan published in the Federal Register contains two important provisions that are distinct from previous marketing plans and contracts. One, the power contracts have an extended duration from 20 years in the Post-2004 period to 40 years in the Post-2025 period. Contractors view the extension of contract duration as a beneficial modification as will be discussed in Section 2.3 (under Question 2). Two, WAPA reserves the right to adjust, at its discretion and sole determination, the CROD on 5 years advance written notice in response to changes in hydrology and river operations (Federal Register Vol. 81, No. 229, 2016, p. 85949). This second provision gives WAPA the authority to reduce its firm power obligation to customers with changes in hydrology.

Based on an interview with WAPA staff and review of the draft 2025 firm electric service contract, it was observed that the Post-2025 contract contains a third important modification. This modification pertains to the resale prohibition principle. As with the most recent, i.e. 2017, Hoover power contracts, the Post-2025 SLCA/IP power contracts have modified the sale for resale provision to allow customers to utilize capacity and/or energy under this contract with an “entity or entities that coordinate, control, monitor, or support operation of the bulk electric system, or act as a marketplace operator of wholesale power, or procure products or service on behalf of any such entity, including but not limited to independent system operators, regional system operators, transmission organizations, balancing authorities, or successor organizations” (Draft Default 2025 Contract, 2017). This provision increases the flexibility available to customers in responding to the ongoing changes in the electricity sector.

2.3 Operational Level

The foregoing sections discussed the major constitutional and collective-choice arrangements that govern dam operations and hydropower generation along with power marketing, allocation, and contracting at Hoover and Glen Canyon Dams. The aim of this section is to contextualize these higher-level institutional arrangements for day-to-day dam operations. Within IAD, exogenous variables are thought to impact action situations producing certain outcomes. While discussing day-to-day operations separate from outcomes would fit the structure of the foregoing sections of the paper, these two elements have been discussed in tandem in this section as it is easier to visually see the impact of governing institutional arrangements on hydropower generation. Moreover, visualizing the changes in hydropower generation is also useful to understand not only the reasons why despite generation constraints and climatic uncertainty customers continue to invest in this resource, but also the potential economic consequences of these change in hydropower generation for energy users, irrigators and the environmental programs.

This section is therefore organized under three leading questions–i) how do governing institutional arrangements impact dam operations and hydropower generation, ii) how do governing institutional arrangements pertaining to energy and power contracts impact the multiple reasons why customers value hydropower, and iii) how do changes in hydropower generation impact energy users, irrigators and the environmental programs.

Question 1: How do governing institutional arrangements impact dam operations and hydropower generation?

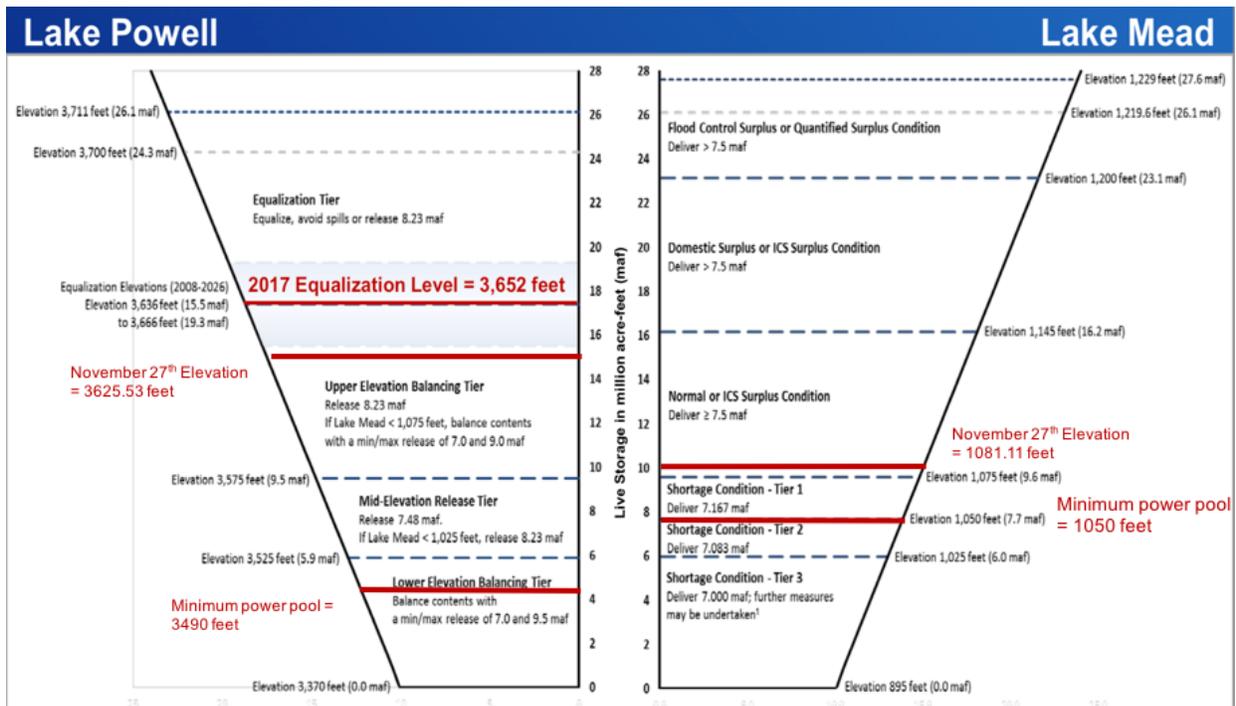
Before discussing how the constitutional and collective-choice level institutional arrangements impact dam operations and hydropower generation at Hoover and Glen Canyon, it is important to first understand the mechanics of hydropower generation itself.

Hydropower is the conversion of kinetic energy of moving water into mechanical energy of moving turbines, which in turn converts to electricity (Reclamation, 2005). Two parameters are absolutely critical for hydropower generation: hydraulic head and flow. Dams create hydraulic head, from which water flows. The hydraulic head depends on the elevation of water in the dam; water has to be available at a height above what is called the ‘minimum power pool’ level—the elevation below which electricity cannot be generated—to create sufficient head to generate electricity.

Institutional arrangements affect both the hydraulic head and flow in the Colorado River Basin. Institutional arrangements pertaining to water—specifically, 2007 Interim Guidelines, which are based on the 1922 Compact Requirements and LOCR—impact the hydraulic head of Hoover and Glen Canyon Dams as they dictate annual water release criteria for the dams based on the water elevation in Lakes Mead and Powell. A hypothetical example of how this works is as follows. In August, each year, Reclamation determines the expected lake elevations at Lakes Powell and Mead as part of its 24-month study. On November 27th 2017, Lake Powell’s elevation was 3625.53 feet (above mean sea level), and Lake Mead’s elevation was 1081.11 feet (above mean sea level). Figure 3 below shows the annual water release schedules per the 2007 Interim Guidelines⁶⁸. Given November 27th elevations then, Lake Powell is in the Upper Balancing Tier, and Lake Mead in the Normal or ICS Surplus Condition Tier (slightly above the Shortage 1 Tier). What this means for annual water release is that Glen Canyon will release at least 8.3 million acre-feet water to Lake Mead; however, given the hydrological variability, Glen Canyon could release more water, if in April next there is more active storage in Lake Powell.

⁶⁸ Note that the author created this figure for illustrative purposes only

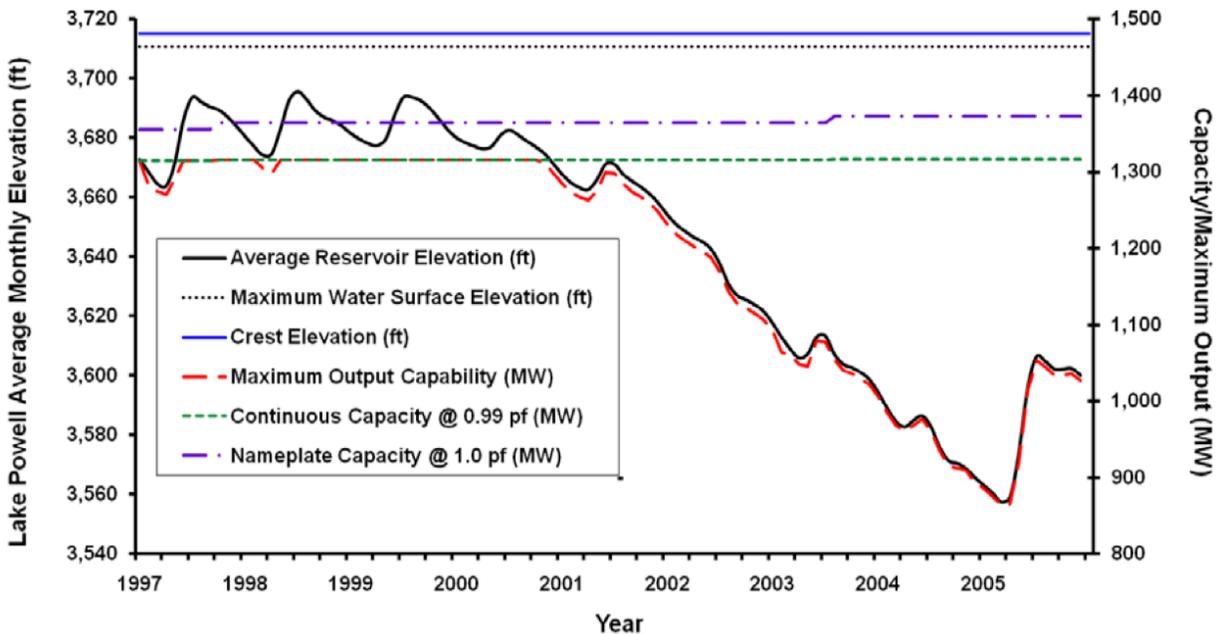
Figure 3 Schematic of the 2007 Interim Guidelines



Source- Author’s adaptation based on a schematic of the 2007 Interim Guidelines presented by Bunk (2017)

Reservoir elevations play a vital role in determining the hydropower generating capacity at Glen Canyon and Hoover Dam; hydropower generating capacity can rapidly decline at lower lake elevations. Figure 4 shows an example for Glen Canyon; notice that the red line (maximum output capability), which shows how much hydropower can be generated, declined rapidly with change in average reservoir elevation from 2001 to 2005. The installed hydropower generation capacity at Hoover and Glen Canyon Dams is 2074 MW and 1320 MW; however, with changes in lake elevation, the actual operational release capacity at the two dams has decreased by over 25 percent, with Hoover operating at 1558 MW and Glen Canyon operating at 990 MW in 2016 (WAPA, 2017b).

Figure 4 Changes in Glen Canyon Hydropower Output Capability Based on Changes in Lake elevations



Source- Argonne National Laboratory, 2010

The 2007 Interim Guidelines, have a greater consequence for hydropower production at Glen Canyon Dam, than at Hoover Dam. This is due to the fact that Lake Mead has an ‘intentionally created surplus’ program as well as agreements on drought water management with Mexico (see for example Minute 318 and Minute 319) that create a buffer for the operating head for Hoover Dam. In 2016, for example, these efforts and Minutes resulted in nearly 10 additional feet of water elevation at the end of the year (Carter et al., 2017). Moreover, starting 2012, the existing turbines at Hoover Dam were being replaced with ‘low-head’ turbines, which would allow power production at elevations as low as 950 feet (Thompson, 2015). Similar agreements and technological upgrades are not being undertaken at Glen Canyon Dam.

Flow, on the other hand, is dictated by a larger set of institutional arrangements pertaining to water, environment, and energy. These institutional arrangements pose different operational constraints for Hoover and Glen Canyon Dam, and can be broken down and discussed in three time-steps:

Annual: The 1922 Colorado River Compact, the 1944 Mexican Water Treaty, and the LROC and 2007 Interim Guidelines that dictate the total amount of water that has to be released from the Upper to the Lower Basin, and from the Lower Basin to Mexico each year. As

discussed earlier, these annual level releases affect reservoir elevations, which can in turn affect hydropower generation.

Monthly: Recollect that water for agricultural and municipal needs has a higher priority over water for hydropower generation in the Basin according to the 1922 Compact. For Hoover Dam, specifically, the same prioritization exists as the 1922 Compact as stated in the BCPA 1928. Based on the BCPA 1928 and individual water delivery contracts signed by water users with the Secretary of the Interior, monthly water release determinations are made by Reclamation based on the estimated (or requested) water needs in the Lower Basin (Interview with staff at Reclamation, 2017). These monthly water release estimates are then sent to the power operations team that oversees electricity generation at Hoover Dam. Using the water release schedule, the power operations team then optimizes the total electricity that can be generated in any given month (Interview with staff at Reclamation, 2017).

In case of Glen Canyon Dam, on the other hand, the Grand Canyon Protection Act 1992, and subsequent Records of Decisions (1996 and 2016) require monthly releases to be made such that they not only meet the annual delivery requirements from the Upper Basin to Lake Mead, but also to improve downstream resources that are of importance environmentally and also to Indian Tribes (See Record of Decision 2016, p. 1). Per the latest Record of Decision (2016), monthly releases from Lake Powell to Mead are evenly distributed throughout the year, with a slight increase in releases in August to allow added hydropower generation (p. 2). The monthly water release data is then used by the power operations team in the Upper Basin to estimate the total electricity generation for the month (Interview with staff at Reclamation, 2017); however, unlike Hoover Dam, there are added constraints for power generation at Glen Canyon as will be discussed below.

Daily: While institutional arrangements pertaining to water and environment determine flow at annual and monthly time-steps, power contracts—along with additional operational rules in the case of Glen Canyon Dam only—dictate daily water releases at Hoover and Glen Canyon Dams. Power contracts affect daily dam operations and hydropower generation by creating specific rules around how customers can ‘schedule’ generation at the dams. Before we delve deeper into the contract provisions that affect daily operations of Hoover and Glen Canyon Dams, it is important to understand the concept of scheduling generation.

Unlike water or gas, electricity cannot be stored in large quantities. It must be generated the instant it is used, which requires a constant balance between demand and supply. To allow

this balancing, load serving entities (LSEs)⁶⁹ determine the total load⁷⁰ and the load profile, i.e. the variation in demand/electric load over time, of their service area to determine the total amount and pattern of generation that will be required to meet the projected electricity demand. Once the amount and pattern of generation is determined, LSEs⁷¹ ‘schedule’ generation dispatch of the various resources such as natural gas, coal, hydropower, wind, etc. in their portfolio (or through a market) at various times of the day such that characteristics of the various resources are considered to meet the demand pattern of that day. Scheduling therefore occurs prior to generation. Moreover, it can occur at multiple timesteps, i.e. hourly, daily, weekly etc. Laws, policies, and/or contracts typically outline the terms of how such scheduling can occur. For example, a contract for a specific resource may require a customer to schedule at least a minimum ‘x’ amount of energy from that resource that it is allotted to the customer in a given hour or a contract may impose penalties if the customer schedules energy over or under its allocation by a specified percentage (or amount). Contract provisions can thus dictate daily flow by influencing how daily scheduling of the hydropower resource can occur.

Based on Reclamation’s hydrological projections, Hoover power contracts mandate WAPA to create and provide customers a ‘Master Schedule’ annually that includes the 17-Month operating schedule for Hoover power plant showing estimated capacity and outages each month as well as a power generation schedule based on the best available forecast of energy (Electric Service Contract No.16-DSR-12626, 2016). Included in this Master Schedule is the respective customer’s available capacity and energy on a monthly basis. A customer can then schedule generation of its available energy up to its available capacity on an hourly basis. For example, if a customer has an available capacity of 100 MW for a given hour, it can schedule up to 100 MWh of energy generation for that hour.

Hoover power contracts require customers to schedule generation in advance—i.e. preschedule—but allow modifications in such schedules to the needs of day-to-day or hour-by-hour operations based on specific metering and scheduling instructions (Electric Service Contract No.16-DSR-12626, 2016). Customers can submit both ‘static’ and ‘dynamic’ energy schedules on an hourly/real time basis. Static schedules are submitted in 15-minute increments whereas dynamic schedules can be communicated via a data link in the form of energy requests in up to 4 second increments (Interview with staff at WAPA, 2017). It is this dynamic scheduling

⁶⁹ The North American Electric Reliability Corporation (NERC) defines LSEs as “entities that secure energy and transmission services to serve the electrical demand and energy requirements of its end-use customers” (NERC, 2018).

⁷⁰ NERC defines load as “an end-use device or customer that receives power from the electric system” (NERC, 2018).

⁷¹ This is not to say that only LSEs schedule generation. A Balancing Authority—an entity tasked with the responsibility to balance load to generation on a real-time basis in a given geographical area— “receives generation dispatch plans and/or generator commitment and dispatch schedules from any, or a combination of, the following entities: Purchasing-Selling Entity, Market Operators, Generator Operator, Generator Owner, that have bilateral arrangements for generation within the market or the Balancing Authority Area” (NERC, 2008, p. 9).

capability coupled with a customers' right to use—and WAPA's obligation to provide—previously scheduled generation for ancillary services under the contract that creates immense flexibility in a customer's ability to use this resource as well as wide variability in daily water releases from Hoover Dam (Electric Service Contract No.16-DSR-1262, 2016, see Section 6.11.2 and 6.1.2.2).

Hoover Dam has an automatic generation control system (AGC) that can be used by a customer or its authorized representative or Scheduling Entity to dynamically schedule generation. In the context of ancillary service provision, dynamic scheduling works as follows. A customer, for example, has an available capacity of 200 MW for a given hour. This customer preschedules the entire available capacity for that hour; however, based on operational needs only ends up using 100 MW of capacity over some part of the hour. The customer thus has an additional 100 MW prescheduled capacity and associated energy at its disposal for the rest of the hour that it can then use for ancillary services. Once a customer sends a dynamic signal to either ramp up (or down) generation based on prescheduled capacity and energy for the hour, the AGC system responds to this signal in as little as 4 second intervals. This is near instantaneous from the perspective of grid operations and consequently valuable to the energy customers (Interview with staff at WAPA, 2018).

In addition to the dynamic scheduling capability, Hoover power contracts have limited minimum scheduling restrictions on an hourly basis to meet minimum power system or water delivery requirements. WAPA may require customers to schedule up to 10 percent of the customer's available capacity for the current and next hour, if necessary during low load hours when system frequency is high. Alternatively, WAPA may require customers to schedule energy during off-peak hours, not exceeding 25 percent of the customer's monthly allocation, to meet minimum water release requirements (Electric Service Contract No.16-DSR-1262, 2016, see Section 6.9.3). The limited minimum scheduling restriction coupled with the absence of environmental constraints and ability to send dynamic schedules allows customers to not only use Hoover to meet energy needs during hours of peak demand when the economic value of hydropower is high (Reclamation, 2006)⁷², but also to ramp up and down, i.e. use the ancillary service of spinning reserves, to address grid reliability issues near instantaneously.

Hoover Dam, within the constraints posed by institutional arrangements on annual and monthly releases and other operational issues such as repairs and planned outages, can still operate the same way on a daily basis as it did over the last three decades as can be seen in the

⁷² Compared to other conventional sources of power (such as coal, nuclear, and natural gas), the marginal cost of generating electricity at a hydropower station is cheaper as the fuel for generating electricity is free. Consequently, this hydropower is used to meet electricity needs of energy utilities during hours of peak demand, i.e. hours when the demand for electricity is highest and the variable cost of meeting this demand is also the highest (Reclamation, 2006).

daily fluctuations in energy generated at the dam (Figure 5), and a linear trend in monthly electricity generation at the dam (Figure 7).

In case of Glen Canyon Dam, on the other hand, the 1996 and 2016 Record of Decision as well as scheduling provisions within the SLCA/IP power contract limit the variability in water flow on a daily basis. We will first discuss contract provisions followed by the constraints posed by the 1996 and 2016 Record of Decision.

Unlike the 17-month Master Schedule that determines the capacity and energy available to each Hoover power contractor on a monthly basis, SLCA/IP power contracts require WAPA to determine resource availability every season, i.e. summer and winter, based on hydrological conditions, projected water releases and operational considerations (i.e. outages, repairs, etc.). At least 60 days before the beginning of each season WAPA establishes monthly capacity and energy availability for the season (Draft Default 2025 Firm Electric Service Contract, n.d., Section 7.8). Customers are then required to preschedule electrical energy with WAPA on an hourly basis (Draft Default 2025 Firm Electric Service Contract, n.d., Section 10.2). This makes SLCA/IP power a static resource as it does not allow customers to schedule power dynamically such as in the case of Hoover power.

SLCA/IP contracts additionally set three limits on the amount of electrical energy that customers can schedule on an hourly basis: minimum amount per hour, maximum amount per hour, and total amount of energy within a month (Warren, 2008). SLCA/IP power contracts require customers to schedule a minimum of 35 percent of their total CROD, or total load, whichever is less, on an hourly basis (Draft Default 2025 Firm Electric Service Contract, Section 7.9). This requirement creates a “minimum take” level on an hourly basis and customers use this as a “base” resource (Warren, 2008). The remaining available capacity and energy, i.e. 65 percent of CROD up to customer’s the total load, can be scheduled by the customer on a “load following” basis (Warren, 2008). That is, after the base resource has been scheduled, customers can schedule the remaining available capacity and energy for the day when the demand for electricity is high. Load following occurs up to the maximum capacity allowed under the contract; this load following capability is the extent of flexibility made available to customers in their ability to schedule CRSP resources.

Figure 5 Daily Hydropower Generation at Hoover Dam

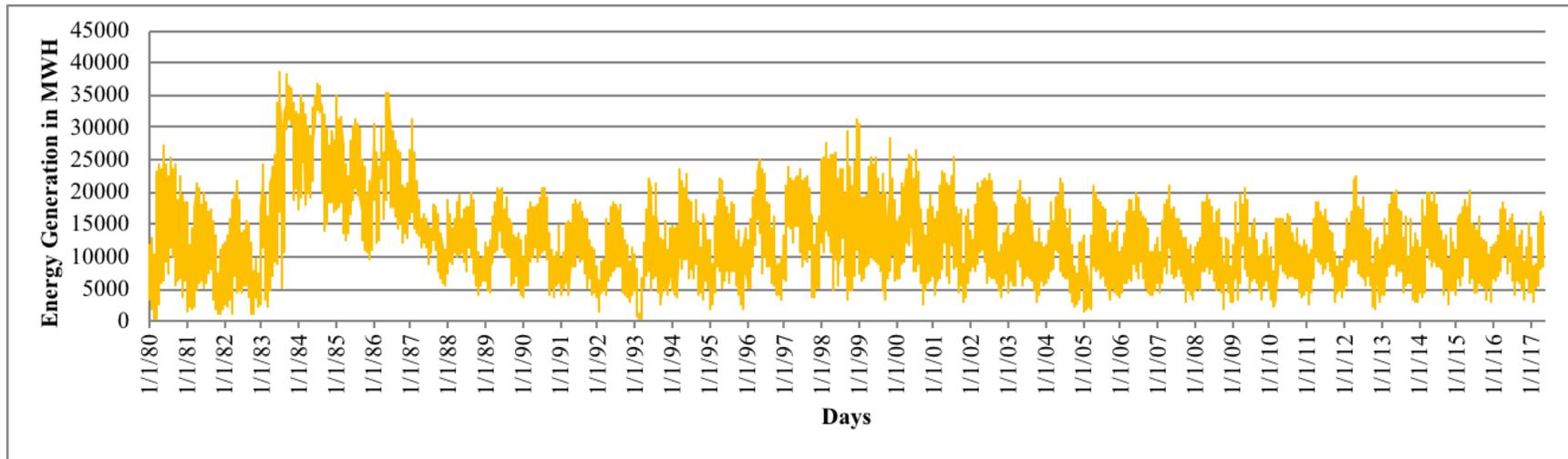


Figure 6 Daily Hydropower Generation at Glen Canyon Dam

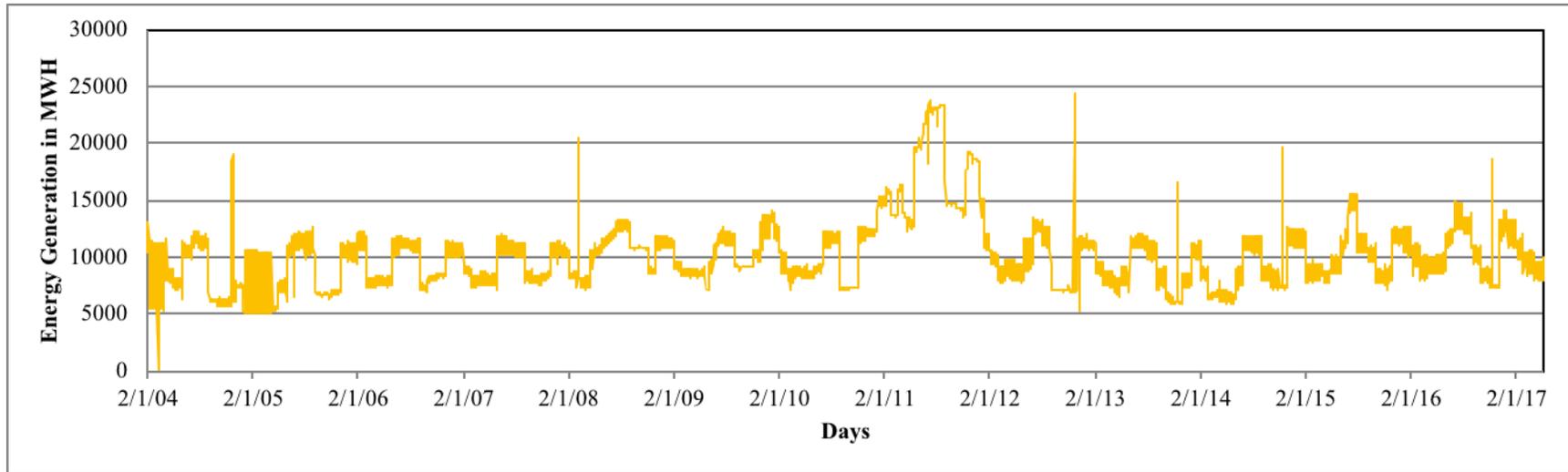


Figure 7 Monthly Hydropower Generation at Hoover Dam

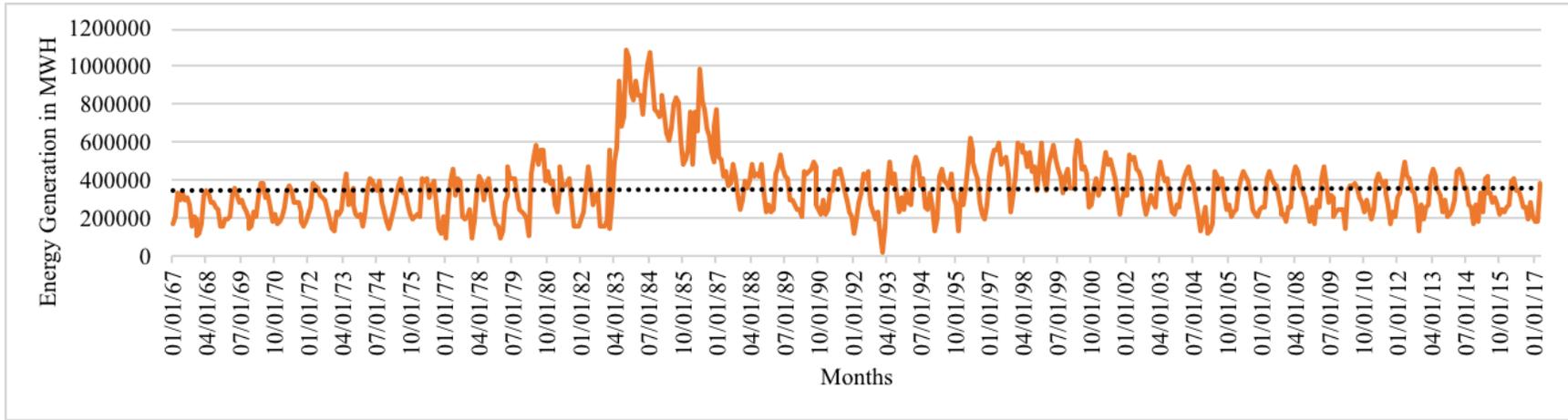
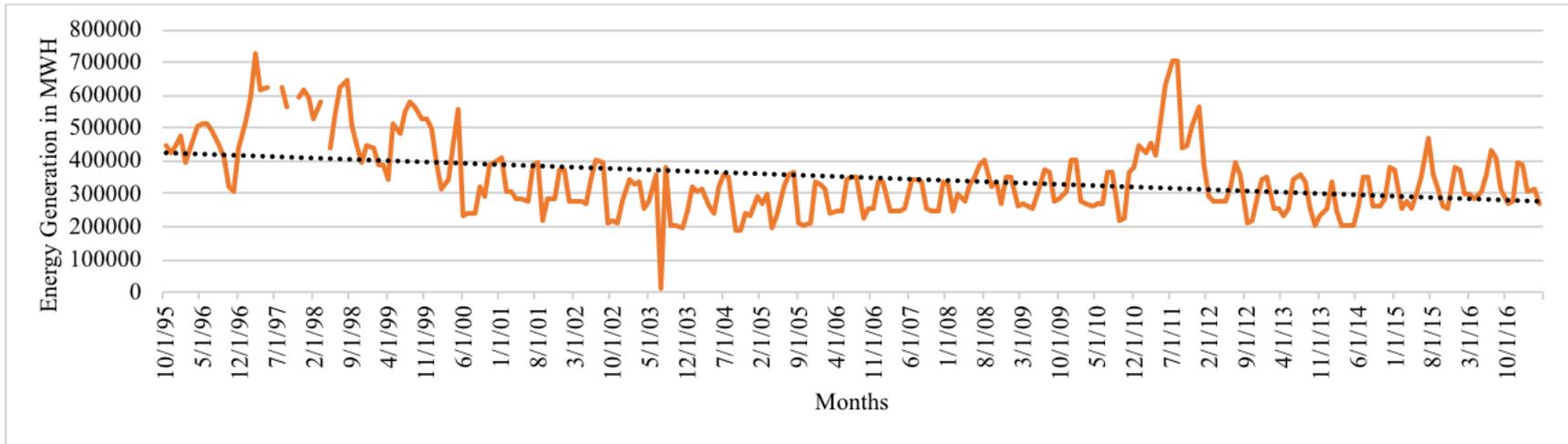


Figure 8 Monthly Hydropower Generation at Glen Canyon Dam



The 1996 Record of Decision (RoD 1996) laid down stringent operating rules for releasing water to meet environmental needs downstream of Glen Canyon Dam. This decision effectively limited the amount of daily fluctuations in water levels that could be permitted out of Glen Canyon Dam (WAPA, 2015a). The newer Record of Decision, i.e. RoD 2016, maintains the restrictions on daily fluctuations of water releases as in RoD 1996, and, in fact, increases the latitude given to Reclamation to modify daily flows to ‘adapt to changing environmental and resource conditions and new information (see for example Attachment B generally and Table 4 specifically of Glen Canyon Dam Final Environmental Impact Statement, 2016).

The aforementioned scheduling restrictions in SLCA/IP contracts were developed to consider the water release constraints imposed by the 1996 and 2016 RoD. When compared to the daily electricity generation pattern at Hoover Dam, the impact of these restrictions, can be seen in Figure 6 for Glen Canyon Dam, where the daily fluctuations are restricted, and there is an overall decrease in monthly electricity generation as can be seen in Figure 8. These criteria reduce the flexibility of daily operations and thereby diminish the ability to respond to market price signals, and lower the economic and financial benefits of power production (Argonne National Laboratory, 2013).

On observation these charts, there are some visible spikes in energy generation. These correspond to periods of experimental water releases, such as for the high-flow experiments. One could argue that the increase in hydropower generation was beneficial to resource users. However, as timing and quantity of releases are both critical factors that determine if, and to what extent hydropower can be used when it is most valuable economically, the high-flow experiments in fact were not as beneficial from an economic-standpoint despite the high water release volumes. As hydropower was generated at times of low demand during these high flow experiments, the resultant electricity that was generated had to be sold on the market at a lower price (Jeka, 2016; Argonne National Laboratory, 2013).

Question 2: How do governing institutional arrangements pertaining to energy and power contracts impact the reasons why customers value hydropower?

In the Colorado River Basin, when customers sign power contracts they also take on the economic responsibility for paying for a host of costs associated with the construction, operation, and maintenance of dams and other costs assigned to power users, such as aid to irrigation. Power customers have to pay these costs whether or not they actually receive their allocated share of hydropower. In the context of climatic uncertainty, growing constraints on dam operations imposed by water and environmental laws, and reduction in hydropower generating capacity at both Hoover and Glen Canyon Dams, one would assume that customers would be

wary of signing contracts for hydropower, especially since their economic responsibility does not decrease or disappear with changes in power output from dams.

Despite the seeming risks associated with signing hydropower contracts in an era of climatic uncertainty, all customers that received hydropower from Hoover and Glen Canyon Dams chose/have chosen to continue investing in this resource by extending their Hoover and SLCA/IP contracts beyond their expiration in 2017 and 2024 respectively⁷³. During interviews, customers explained that they continue to invest in CRB hydropower as it is valuable to them for four main reasons: flexibility, cost, reliability, and ‘clean’ characteristic. The subsequent sections discuss how institutional arrangements pertaining to energy and power contracts influence each of the four reasons why customers value hydropower.

a. Flexibility

The term flexibility as used by power customers during interviews pertains to how customers can use their hydropower allocation. This includes flexibility in scheduling generation on a daily basis as well as flexibility in using this resource in a rapidly changing energy market. Power contracts determine the degree of flexibility available to customers in using their hydropower allocations on both accounts, i.e. scheduling generation and using their allocation in a rapidly changing energy market. Hoover and Glen Canyon Dams cannot be operated with the same degree of flexibility; this is an artifact of the differences in power contract provisions for the two dams as will be discussed below.

Hoover power contracts enable customers to dynamically schedule generation and use the prescheduled generation for ancillary services (see discussion under Section 2.3, Question 1). The power contracts allow customers to use Hoover Dam’s automatic generation control system to send a dynamic signal that can prompt changes in electricity generation at the dam based on changes in customers’ needs. During interviews, the staff at WAPA and large power customers in California and Arizona explained that this ability to schedule generation dynamically and use prescheduled generation for ancillary services makes Hoover an immensely flexible resource as customers can use this resource to serve peak energy needs as well as respond to fluctuations in generation or energy demands. The interviewees also noted that the value of this flexibility has increased over the last few years with the growth in grid penetration of intermittent renewable resources, particularly wind and solar⁷⁴. This point raised by the interviewees is also evident in

⁷³ In fact, in the Post-2017 power reallocation process for Hoover where a 5 percent power pool was created for new customers, the applications for this power surpassed the amount of power that was available for allocation.

⁷⁴ A staff member at an electrical district in NV further mentioned that while thermal power units can provide some of the services necessary to integrate renewables, hydro is the only ‘clean’ resource that can provide the same type of services. The staff member said, “in order to have enough renewables, you’re almost going to have to include hydro because there just isn’t anything on the market [that is clean] that can give you power when you need it, for instance in the evening hours, hydro can do that for you, and nobody is going to consider oil or natural gas renewable. It’s just not going to happen.”

the results of the modelling study conducted by Acker and Pete (2012) where the scholars found significant changes in operations at Hoover Dam with rising penetration levels of wind and solar generation (Chapter 9, p. 3).

The largest Hoover power contractors use dynamic scheduling and ancillary services “a lot” (Interview with staff at WAPA and three utilities in CA, AZ, and NV, 2018). Particularly, in the recent years, large customers that also serve as Balancing Authorities or Scheduling Entities for smaller customers have benefitted from the ability to use the spinning reserves—a type of ancillary service—at Hoover to not only integrate variable wind and solar generation in their Balancing Area but also maintain grid reliability (Interview with staff at a utility in AZ, 2018).

The most recent Hoover power contract, i.e. 2017-2067, modified the resale prohibition by allowing customers to utilize their Hoover capacity and/or energy “with an entity or entities that coordinate, control, monitor, or support operation of the bulk electric system, or act as a marketplace operator in wholesale power, or procure products or service on behalf of any such entity, including but not limited to independent system operators, regional transmission organizations, Balancing Authorities, or successor organizations associated with the Contractor’s load” (Electric Service Contract No.16-DSR-1262, 2016, Section 9.2). This contract modification has increased contractors’ flexibility to use their Hoover power allocation and respond to changes in energy markets, which in turn has enhanced the value of this resource to customers (Interview with staff at a utility in NV, 2018).

33 of 46 Post-2017 Hoover power contractors are located in California and many currently participate in the California Independent System Operator (CAISO), the largest Balancing Authority in the Western Interconnection (Lewis-Roberts, 2016). In addition, Hoover power contracts in AZ have also announced plans to join CAISO’s Energy Imbalance Market (Western Energy Imbalance Market, 2018). Against this background, the ability of customers to use their Hoover power allocation in ISOs, RTOs or bulk power markets is valuable to customers for two reasons. One, it enables customers to use all the resources in their portfolio in a more efficient manner. For example, if a customer does not need hydropower in a given hour due to the availability of other resources in its portfolio or operational requirements of specific generation sources, it can sell its hydropower allocation on the market to someone else that needs it. This provides customers with a “terrific advantage” to use their resources efficiently and in an economically beneficial manner (Interview with staff at a utility in NV, 2018). Two, customers are able to provide ancillary services that are sought after in ISOs and bulk energy markets that need to balance generation and load and maintain grid reliability at all times⁷⁵ (Interview with staff at WAPA, 2018).

⁷⁵ During the conference of Western Public Service Commissioners Lewis-Roberts (2016) underscored how contract provisions pertaining to ancillary services aided customers in “capturing the value of Hoover Power”.

A written application by Southern California Edison—one of the oldest customers with one of the largest allocations of Hoover power and the only IOU to receive an allocation—before the California Public Utilities Commission (CPUC) for the approval of its Post-2017 Hoover power contract highlights similar points as those raised by interviewees. Southern California Edison (SCE) noted that the “Hoover ESC [electric service contract] *benefits include electrical energy, ancillary services, and resource adequacy values*...[and the current contract] includes negotiated *provisions that provide flexibility to respond and adapt to future competitive energy markets*, to accommodate new or expanded Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), and to use current and future [ancillary services] AS products” (CPUC, 2016, p. 6, emphasis added). While the other arguments put forth by SCE in support of the Hoover power contracts will be discussed further under sections ‘cost’ and ‘clean’ characteristic below, CPUC approved SCE’s application for Hoover ESC on grounds that power from Hoover was “an important resource for the California market because of its quick-start dispatch capabilities and zero-emission profile, which [was] especially important as California’s power supply draws from more intermittent resources” (CPUC, 2016, p. 7).

Compared to Hoover power contracts, SLCA/IP contracts do not provide customers the same degree of flexibility in scheduling generation from Glen Canyon Dam as customers can only send static schedules to WAPA on an hourly basis and do not have access to an automatic generation control system⁷⁶, such as in the case of Hoover (Interview with staff at utilities in AZ, NV, 2018). SLCA/IP power contracts do contain some flexibility as they allow customers to schedule generation of their energy allocation that is in excess of the ‘minimum take’ during hours of peak demand (see Section 2.3, Question 1) This load-following capability makes Glen Canyon (i.e. SLCA/IP) hydropower a valuable addition to customers’ energy portfolio as it allows customers to use the other generating sources in the portfolio more effectively. For example, an SLCA/IP customer in Arizona that owns thermal generating units indicated that these units are not efficient at a lower rating, i.e. when they are operated below their rated capacity, and cost more money and release greater amounts of carbon-emission when turned on and off. In this case, hydropower from Glen Canyon allows the customer to run its thermal units more efficiently, i.e. at a constant and high rating, which is better from an economic and carbon-emissions standpoint.

Like the modification of the resale prohibition provision in the recent Hoover power contracts, SLCA/IP power contracts also allow customers to utilize their allocation of capacity and/or energy in an RTO, ISO, or bulk energy market. While this contract modification increases the flexibility available to customers in using this resource in a changing energy market, the

⁷⁶ This said, Glen Canyon Dam does have an automatic generation control system, but this is accessible to WAPA as the operator of the Western Area Colorado Missouri (WACM) balancing authority area. The Glen Canyon Dam power plant responds to a regulation signal developed and electronically transmitted to the dam by WAPA for continuous response to power system load and frequency changes. With the growth in wind penetration, the need for Glen Canyon’s regulation services has gone up “dramatically” (Interview with staff at WAPA, 2018).

restrictions in terms of scheduling generation limit the overall flexibility available to customers (Interview with staff at utility in AZ, 2018). WAPA is currently exploring the possibility of including the Colorado River Storage Project in the Southwest Power Pool, an RTO that manages transmission in fourteen states and operates an energy market (WAPA, 2017e; FERC, 2017b). However, even with the presence of an RTO, the operational flexibility in using CRSP resources (and the ability of customers to use this resource in the market) will depend on the constraints imposed by institutional arrangements pertaining to water and environment, and power contracts.

b. Cost

During interviews, customers said that despite the economic responsibility they shoulder for dams and irrigation investments in the Colorado River Basin they still value hydropower because this resource is “cost-effective” as the rates they pay for hydropower are “very reasonable and low” and the rates remain stable for long periods of time (Interviews with staff at utilities in CA, AZ, NV, CO, NM, WY, 2018).

Rates charged for hydropower are very reasonable and low because Boulder Canyon Project Adjustment Act of 1940, Reclamation Project Act of 1939, and Flood Control Act of 1944 require WAPA to sell hydropower generated at Hoover and Glen Canyon Dams on an “at cost” basis (WAPA, 2016b). The at cost principle requires WAPA to set its power rates to cover all *actual* costs associated with power generation and transmission, including costs assigned to power users by governing constitutional and collective choice level laws. WAPA’s rates are thus neither based on “what the market will bear” nor include any type of profit or return to shareholders (WAPA, 2016b).

Rates charged for Hoover and SLCA/IP power are stable because power contracts require WAPA to revise rates only when revenues generated through power sales are insufficient to cover all the costs assigned to power users. Major rate revisions occur every five and undergo a final review and approval by FERC (Electric Service Contract No.16-DSR-12626, 2016; Interview with staff at WAPA, 2018). FERC reviews the assumptions and projections used by WAPA in formulating rates and ensures that the rates are “*the lowest possible to customers consistent with sound business principles*” and that the revenue levels generated by the rates are sufficient to recover the costs of producing and transmitting electric energy along with other costs assigned to power by laws passed by Congress (Department of Energy, 2016b, p. 1, emphasis added). In between major rate revisions WAPA is allowed to review rates annually to account for any changes in revenue requirements such as revision of Base Charge for Hoover power or imposition of a Cost Recovery Charge for SLCA/IP power (see for example Federal Register, Vol. 83, No. 146, 2018, pp. 36586-36588; Osiek, 2018). As part of the annual review, WAPA works with customers to increase, decrease, or defer charges if necessary. The SLCA/IP

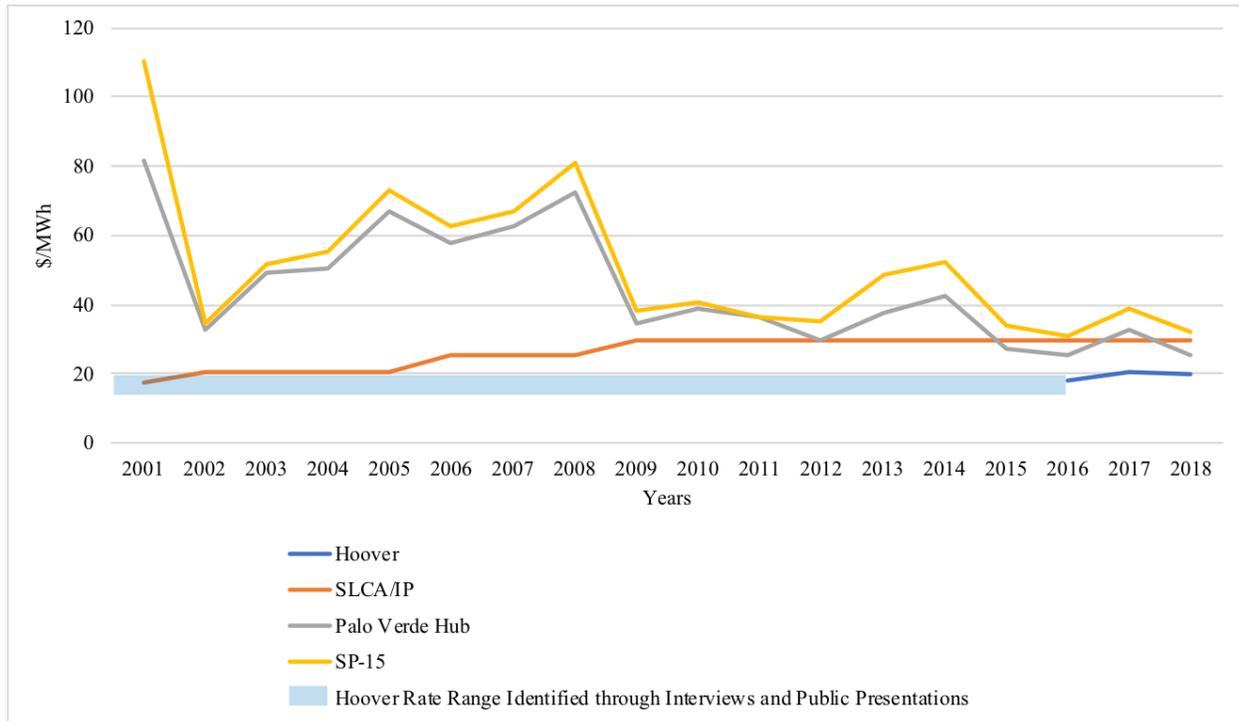
Cost Recovery Charge (CRC) is directly linked to the expense incurred by WAPA in purchasing addition power to meet its firm power obligation under Colorado River Storage Project Act of 1956. To give customers the flexibility in responding to a CRC, SLCA/IP rates include a provision wherein WAPA establishes a ‘Waiver Level’ that reduces purchase power expense by delivering less energy than contractually required. Customers that choose to voluntarily schedule reduced allocation based on the Waiver Level are exempt from the CRC (Osiek, 2018).

The fact that Hoover and SLCA/IP rates are low and stable can be observed when they are compared with wholesale electricity market prices at two trading hubs that are closest to Hoover and Glen Canyon: Palo Verde Hub and SP-15 (Southern California)⁷⁷. Figure 9 shows the composite rate for Hoover and SLCA/IP along with weighted average price⁷⁸ for electricity at Palo Verde Hub and SP-15 over the last 18 years. It must be noted that WAPA generates composite rates for Hoover and SLCA/IP for comparative purposes only as the actual rate customers pay for capacity and energy is based on their allocation (Interview with staff at WAPA, 2018). 2001 was selected as the first year for comparing rates as the U.S. Energy Information Administration began republishing electricity market rate data collected by Intercontinental Exchange in 2001 (EIA, 2018c). For Hoover, composite rates were publicly available for 2016, 2017, and 2018 on WAPA’s website. However, based on public presentations by Hoover customers (MWD, 2016) and interviews with Hoover customers, it was noted that composite rates at Hoover have been in the range of \$15-20 since 2001. The chart therefore shows a solid blue line indicating the publicly available rates and a lighted blue bar indicating the rate range gleaned from interviews and public presentations.

⁷⁷ Typically, studies that calculate loss in revenue due to specific environmental restrictions at Glen Canyon use market prices at Palo Verde for comparison. Consequently, Palo Verde and SP-15 are used for comparative purposes as they reflect the range of prices customers pay for electricity in the region if they were to buy it from the market.

⁷⁸ Unlike hourly or more granular deals for ISO and RTO markets, customers in regions without organized markets purchase a block of 16 hours of on (or off) peak energy at a single price. Consequently, in areas without organized markets but with designated trading hubs, such as Palo Verde, a weighted average price index is created that refers to the “volume-weighted average that represent[s] the price of a commodity at a particular place and time” (FERC, 2004, p. 53). The volume-weighted average price is developed by collecting transactional data from market participants at the given hub. Volume-weighted average price is published at the end of the trading day; as a result, this price reflects day-to-day and seasonal changes, but not the real-time changes in prices (FERC, 2004, p. 53).

Figure 9 Hoover and SLCA/IP Composite Rates Compared to Wholesale Electricity Market Prices



Important note- This chart has been created for illustrative purposes only. Hoover and SLCA/IP composite rates are used for comparative purposes only and do not represent the actual rates that customers pay for their capacity and energy allocation per month. Palo Verde Hub and SP-15 rates shown in this chart are annual averages of daily weighted average price per MWh. These rates were calculated to indicate the general overall trend in prices and do not reflect the day-to-day fluctuations in weighted average prices. For example, during the 2001 California energy crisis, the daily weighted average price for electricity could fluctuate from \$530/MWh one day to \$360 the next day at SP-15.

As Figure 9 shows, Hoover and SLCA/IP rates have been historically lower than market prices, except in recent years. Wholesale electricity prices are closely tied to wholesale natural gas prices in all but the center of the country (EIA, 2018d). Therefore, the decline in wholesale electricity prices over the last few years has been the result of declining wholesale prices for natural gas. In 2009, and the period since 2015, SLCA/IP rates have been higher than wholesale market prices. In 2018, for example, Palo Verde had an average price of \$24/MWh and there have been instances where the price has been as low as \$17/MWh, which is considerably lower than the SLCA/IP composite rate per MWh (EIA, 2018c). Despite the higher than wholesale market rates, SLCA/IP power is still competitive and economically valuable for customers as it is a “bundled product” (Interview with staff at WAPA, 2018). This means that unlike wholesale market prices, where prices only reflect the cost of purchasing generation without the actual transmission, SLCA/IP rates include the cost of generation and transmission of electricity (Interview with staff at WAPA, 2018). Moreover, WAPA reserves capacity on transmission lines up to its CROD obligation to customers; as a result, customers can use this reserved capacity to receive any energy they might purchase themselves to make up for the shortfall in SLCA/IP

generation up to their CROD allocation without incurring additional transmission charges (Interview with staff at WAPA, 2018).

The “bundled” nature of SLCA/IP hydropower resource and rates is especially important for small customers in remote parts of the Upper Basin that do not own extensive transmission lines or find it expensive to purchase capacity on transmission lines for wheeling power (Interview with staff at utilities in WY, 2018). Customers in Wyoming explained that even though wholesale electricity market prices are low and the cost of generating electricity from renewable sources has plummeted in the recent years⁷⁹, customers cannot easily access these resources as they do not have the economic resources to build their own transmission lines or purchase capacity on existing transmission lines (Interview with staff at utilities in WY, 2018)⁸⁰. Moreover, even if the customers were to purchase capacity on existing transmission lines, the total expense incurred would eliminate the economic advantage of purchasing power in the wholesale market or obtaining it from power plants that generate electricity at low cost (Interview with staff at a utility in WY, 2018). Consequently, hydropower from SLCA/IP remains economically attractive to these small customers in the Upper Basin as they can use WAPA’s transmission lines to access their allocation of hydropower (Interview with staff at utilities in WY, 2018).

Overall, even with a drought, customers still consider hydropower from the Colorado River Basin a cost-effective resource as can be seen in SCE’s application for Hoover power to CPUC where SCE indicates, “[u]nder most expected scenarios, the Hoover ESC is highly cost-effective. *Even under a scenario where resource adequacy capacity was modeled as zero, and energy and ancillary service values fall substantially, the expected overall value of the Hoover ESC is still positive on a net present value basis*” (CPUC, 2016, p. 5).

c. Reliability

Interviewees across the Lower and Upper Basins consider Hoover and Glen Canyon hydropower as a reliable resource despite the looming threat of a drought-induced water shortage. Reliability stems from provisions contained in and characteristics of power contracts. As indicated by the interviewees, reliability refers to two aspects: certainty in receiving the allocated share of hydropower, and certainty and stability in contract terms.

⁷⁹ See for example the 2017 Annual Technology Baseline published by the National Renewable Energy Laboratory (NREL, 2017) that indicates a decline in the levelized cost of energy from solar and wind. Levelized cost of energy is based on three primary cost and performance factors: capital expenditures, capacity factor, and operations and maintenance cost.

⁸⁰ These customers further explained that despite the decline in costs of generating electricity from renewable sources, they themselves could not build new power plants as they did not have the economic resources to support such an investment and their status as municipal power agencies prevented them from accessing incentives, such as tax credits, for building renewable generating sources (Interview with staff at a utility in WY, 2018).

Hoover and SLCA/IP power contracts provide customers predetermined allocations of contingent and firm capacity respectively and associated firm energy, and require WAPA to provide customers advance notice of changes in capacity and energy that can be scheduled. Customers, therefore, have a clear idea of the resources available to them in both the long term (through predetermined allocations) and short term (through WAPA's 17-month Master Schedule for Hoover and Seasonal Schedule for SLCA/IP) (Interview with staff at a utility in CA and a utility that serves CO, WY, NM, 2018). Interviewees indicated that Hoover and Glen Canyon Dams consistently provide customers their allocated share of hydropower with any minor revisions that are necessary due to changes in operating conditions (Interview with staff at utilities in CA, NV, WY, and a utility that serves CO, WY, NM, 2018). All interviewees in both the Lower and Upper Basins further went on to add that they had not experienced unplanned or unexpected disruptions in their hydropower allocations for as long as they could remember, which made this resource highly dependable in their opinion⁸¹.

The second aspect of reliability, i.e. certainty and stability in contract terms, arises due to the long-term nature of Hoover and SLCA/IP contracts (Interview with staff at a utility in AZ and a utility that serves CO, WY, NM, 2018). WAPA's power contracts change only minimally over the entire duration of the contract once they are signed (Interview with staff at WAPA, 2018). The longer the contract duration, the greater the stability in hydropower allocations and contract terms such as scheduling generation and rates for the resource. Consequently, during the most recent contract negotiations, customers pushed to extend the Hoover and SLCA/IP contract duration to the legally permissible maximum term of 50 and 40 years respectively (from the previous 30- and 20-year durations) to ensure stability of contract terms and hydropower allocations (Interview with staff at WAPA, 2018). Contractors value the stability in Hoover and SLCA/IP contracts for two main reasons. One, it allows them to use the long-term contracts as a "hedge" against potential disruptions in electricity generation from other sources, such as when there is a rise in fuel costs (Interview with staff at a utility in AZ, 2018). Two, it provides reliability to utility and town planners that they will be able to access this low-cost resource at favorable terms, which is beneficial for purposes such as developing long-term generation and transmission plans, attracting and maintaining industries and businesses in small towns and rural areas, and providing security for long-term loans associated with investments in hydropower (see arguments for long-term contracts in Federal Register Vol. 51 No. 26, 1986, p. 4853; Interview

⁸¹ Staff at a utility in WY suggested that the large-scale storage available at Lake Mead and Lake Powell added to this reliability. Staff at utilities in CA and WY further went on to add that although Colorado River was facing a drought and water shortage that put hydropower generation at risk, this risk faced by hydropower generation was no different than the risk faced by natural gas and coal-fired generating units due to fuel disruption. In fact, even from a risk perspective, hydropower in the Colorado River Basin had the added advantage of having a fuel storage that may not drastically change from one day to the next (unless there were a dam break, flood, or an unforeseen event that required water releases). This was unlike natural gas and coal-fired generation where fuel disruption could occur potentially occur on a much shorter time-scale, even on the order of a few days, that added to reliability concerns. Staff at a utility in CA gave an example of how the 2015 Aliso Canyon gas leak caused utilities to go from an energy surplus to shortage situation within a few days. During the 2015 Aliso Canyon gas leak in California, emergency agreements were made with WAPA to provide hydropower from Glen Canyon Dam if required (WAPA, 2017d).

with staff at a utility in WY and a utility serving CO, NM, WY, 2018). During a stakeholder interview, an SLCA/IP customer indicated that despite the higher rate of SLCA/IP hydropower compared to the wholesale electricity market prices, the long-term nature of power contracts provides reliability that makes this resource worth the investment in the long run (Interview with staff at a utility serving CO, NM, WY, 2018).

d. 'Clean' Characteristic

All interviewees across the Lower and Upper Basins said that they value hydropower from Hoover and Glen Canyon Dams because it is a 'clean', emission-free resource (Interviews with utilities in CA, AZ, NV, WY, and a utility that services CO, NM, WY, 2018). Unlike flexibility, cost, and reliability, institutional arrangements pertaining to energy and power contracts do not directly influence this last reason why customers value hydropower as it is a characteristic of the resource itself.

The 'clean characteristic' of hydropower generated at Hoover and Glen Canyon Dams does not always produce direct economic benefit for customers. While both Hoover and SLCA/IP contracts contain provision where the 'environmental attributes' of a customers' hydropower allocation can be expressed in the form of renewable energy certificates (RECs), these RECs cannot be used by customers in either cap and trade programs or to meet renewable portfolio standards in the seven Basin States (Interview with staff at a utility in AZ, 2018)⁸². Notwithstanding this limitation, customers at times use this resource to fulfill their internal renewable energy goals (Interview with staff at a utility in AZ, 2018). In the case of California, there is some economic benefit associated with hydropower's 'clean' characteristic as this resource is not subject to a greenhouse gas bid adder when it is used in CAISO Energy Imbalance Market (Interview with staff at a utility in CA, 2018).

Question 3: How do changes in hydropower generation impact energy users, irrigators and the environmental programs?

The differences in collective-choice level arrangements for Hoover and Glen Canyon Dams lead to distinct consequences of changing hydropower generation on resource users. As discussed in the limitations section, assessing consequences involves the consideration of far more variables than those discussed in this paper, which merits further attention.

⁸² While most states in the United States have Renewable Portfolio Standards (RPSs), only a subset includes hydropower in RPSs and other renewable programs (Department of Energy, 2016b). 29 states in the U.S. accept some form of hydropower renewable energy certificates (RECs), but often only those from a small subset of either existing or new resources are eligible (Oak Ridge National Laboratory, 2015, p. 75). Consequently, hydropower RECs are "less liquid, and subsequently less valuable" from an economic standpoint (Oak Ridge National Laboratory, 2015, p. 75).

Notwithstanding these limitations, in case of energy users, the cost of changing electricity generation will be passed on through the need to make additional spot market purchases to meet the requisite demands (Argonne National Laboratory, 2013). As energy customers for Hoover have contingent capacity and associated firm energy contracts, in times of supply deficit, the customers do not incur added costs of purchasing power, unless they request WAPA to make purchases on their behalf in times of demand. In case of energy customers of Glen Canyon on the other hand, as the contracts are set up as firm energy contracts, any deficits in energy generation beyond the SHP need to be met through spot market purchases and these added costs are passed onto the customers. As of 2016, for example, the cumulative purchased power expenses for Glen Canyon have been \$1.7 billion compared to \$11 million for Hoover (WAPA, 2017b).

Beyond the economic impact on immediate energy users, the reduction (or loss) of hydropower generation at Hoover and Glen Canyon Dams could have an impact on the wider electricity grid in the Western U.S. For example, NREL as part of a report on the conditions in the electricity sector that are likely to affect federal decision with respect to Navajo Generating Station, estimated that “an extended drought severe enough to eliminate power generation at Hoover and Glen Canyon Dams could increase the cost of producing electricity by 1.3% to 2.0% across the West” (2013, p. 130). If Hoover and Glen Canyon Dams become unavailable due to a drought, there could be greater reliance on coal and natural gas fired generation, which in turn could increase emissions (NREL, 2013, p. 129). Likewise, Acker and Pete (2012) conducted a modeling study where they observed that if operational flexibility of hydropower facilities is constrained, there is an increase in costs by \$35/MWh for steam oil and gas units and \$60/MWh for generation in the Western Electricity Coordinating Council region; this increase in operating cost provides an indication of the value of hydropower as a system resource (Chapter 9, p. 3).

While Hoover and Glen Canyon power customers have chosen to re-invest in hydropower generation at the two dams thereby ensuring continuity of availability of funding for environmental programs and other uses, any unexpected changes in how revenues are collected or a hypothetical situation where customers terminate their power contracts could have devastating impacts. This is already becoming obvious as a White House recently directed WAPA to redirect \$23 million of Colorado River Storage Project hydropower revenues to the U.S. Treasury instead of using this revenue to fund activities of the Glen Canyon Dam Adaptive Management Program, as well as recovery programs for native fish, both in the upper Colorado River Basin and San Juan River Basin (Colorado River Board of California, 2018). The redirection of funds threatened not only the environmental programs but also the livelihood of agency staff that support these programs (see Sevigny, 2018). Likewise, if energy users from Glen Canyon hypothetically terminate their power contracts, this would jeopardize almost \$2.5

billion worth of unpaid investment for participating irrigation projects and CRSP dams (Jeka, 2016).

Unlike the Upper Basin, energy customers from Hoover do not directly make contributions to participating irrigation projects. Moreover, unlike the Colorado River Storage Projects, only \$2.7 million of the total investment for Hoover Dam remains to be repaid. In addition, energy users' contribution towards the Lower Colorado River Development Fund—the fund used to help repay the costs of constructing the Central Arizona Project as well as pay for the multi-species program—is predicated on the energy that users actually receive. Energy users' contribution for the Lower Colorado River Development Fund is derived out of a surplus that is charged to the actual power delivered to these users from Hoover Dam (WAPA, 2015b); hence, if energy is not delivered, the surplus cost is not charged. Energy users from Hoover, therefore, are not impacted nearly to the same degree as those from Glen Canyon. The flip side, however, is that if energy generation, and in turn delivery from Hoover Dam declines, it impacts the funds available to repay the cost of the Central Arizona Project and the Lower Colorado River Multi-Species Conservation Program.

3. Summary and Conclusions

This paper aimed to explain how water, environment, and energy laws and policies influence hydropower generation in the Colorado River Basin by focusing on two of the largest and strategically important dams in the Basin: Hoover and Glen Canyon. This paper argued that despite the similar biophysical setting for the two dams (due to their location in the same hydrological basin), specific institutional arrangements produced different outcomes for hydropower generation at Hoover and Glen Canyon Dams. To this end, this paper shows that institutional arrangements affect two parameters that are absolutely critical for hydropower generation: hydraulic head and flow. Water laws and policies at the constitutional-choice and collective-choice levels dictate annual and monthly water releases from Glen Canyon and Hoover Dams and in turn affect both hydraulic head and flow. Environmental laws and policies on the other hand affect flow as they impose water releases constraints at monthly and daily time-steps. Power contracts for Hoover and SLCA/IP specify the scheduling requirements for customers and further influence water releases and hydropower generation at a daily time-step.

The analysis shows that water and environmental laws and policies impose specific water release requirements from Glen Canyon Dam at annual, monthly, and daily time-steps. Moreover, SLCA/IP power contracts limit the flexibility available to customers in scheduling generation by imposing specific minimum and maximum hourly scheduling requirements. The

end result is that, even without a drought, water and environmental laws and policies and power contracts constrain operations and hydropower generation at Glen Canyon Dam and at times hydropower is generated at off-peak hours when it does not have the highest economic value. Hoover Dam, on the other hand, faces fewer operational constraints as a result of specific water and environmental law provisions. Hoover power contracts impose limited minimum scheduling requirements on an hourly basis on customers and allow customers to dynamically schedule generation and use prescheduled generation for ancillary services. The effect of limited operational constraints and fewer scheduling restrictions is that, even with a drought, Hoover Dam shows the same degree of flexibility in operations and hydropower production as it did three decades ago.

Even while facing similar biophysical constraints then, this paper shows that constraints imposed by institutional arrangements plays a key role in influencing dam operations and hydropower generation at Hoover and Glen Canyon Dams. While this paper examines only two dams in the Colorado River Basin, we can learn two broad lesson from the findings of this study. One, institutional constraints mediate the impact of biophysical constraints on hydropower operations; even within the same river basin, institutional arrangements can pose different constraints for different hydropower generating facilities and impact the flexibility available to customers is scheduling and using this resource. Two, institutional arrangements can require operators to give certain water uses (such as irrigation and flood control) a higher priority when operating dams; giving other water uses a higher priority may mean that generating hydropower with a pure economic logic, i.e. generating hydropower when the market price for electricity is the highest, may not always be possible.

Hydropower's importance in the electricity sector today is attributed to its ability to operate flexibly in order to respond to the variability and reliability issues caused by growing renewable energy penetration and expansion of electricity markets (Sandia, 2011; Acker & Pete, 2012; Key, 2013; Clement, 2014; Department of Energy, 2016). However, this flexibility may not be available at certain plants not due to the lack of water availability but because of institutional constraints, such as in the case of Glen Canyon Dam. Engineering and modeling studies—particularly production cost modeling studies—that are widely used in the electricity sector to identify the least cost dispatch of a system of interconnected generators recognize the difficulty in capturing hydropower plant-specific institutional constraints in models (Acker & Pete, 2012; Clement, 2014). A failure to account for policy constraints in these models runs the risk of inaccurate representation of the operational flexibility and capacity available at specific hydropower plants, which can result in over/underestimation of hydropower's ability to support

the integration of variable renewable resources and address grid reliability concerns⁸³. To enable a more accurate representation of the flexibility and capacity available at hydropower plants, plant-specific institutional research will be necessary in the future. The analysis carried out in this paper can aid this research process by providing an example of *how* we can identify institutional constraints that influence the flexibility in not only generating electricity at specific dams but also using this hydropower once it is generated.

On the topic of institutional constraints and the ability to leverage the flexibility in hydropower generation in integrating variable renewable generation, a recent development in the Colorado River Basin warrants a brief mention. On 24th July, a New York Times article covered the story of a proposed plan by the Los Angeles Department of Water and Power to use Hoover Dam as a pumped storage facility to address the issue of over generation of solar and wind power in California during off-peak hours (Penn, 2018). This plan, which is still in its exploratory phase, proposes to address the issue of overgeneration by pumping water into Lake Mead during off-peak hours and using the stored water to generate electricity during peak hours. While this plan may be feasible from an engineering and economic standpoint and help California in integrating variable renewable generation, this alone will not be enough to get the plan approved. The plan will need to reckon with legal and policy constraints imposed by institutional arrangements (such as those discussed in this paper) that have been in place since the early 1900s and govern water allocation and dam operations in the Colorado River Basin, which may prove to be more difficult than addressing any potential engineering constraints.

In addition to the argument that institutional arrangements produce distinct outcomes for hydropower generation at dams within the same river basin, this paper posed a second argument. Despite the growing threat of a drought-induced water shortage and the constraints imposed by water and environmental laws and policies for hydropower operations, the paper argued, constitutional and collective-choice level institutional arrangements pertaining to energy and power contracts contain provisions that ensure that hydropower remains valuable to customers in the Basin. Through interviews with power customers, the paper identified four reasons why customers value Hoover and Glen Canyon hydropower: flexibility, cost, reliability, and ‘clean’

⁸³ In addition, some production cost models may use a ‘rational’ dispatch logic, which aims to maximize revenues at hydropower plants or minimize system-wide operational costs, or that assume that hydropower can be dispatched for the benefit of the entire electricity system, that is, not for the benefit of the recipients of the federal hydropower (see for example Acker & Pete, 2012). In practice, the rational logic and assumption that hydropower can be dispatched for the benefit of the entire electricity system may prove only partly plausible at best or unrealistic at worst, especially in the case of federal hydropower plants that are obligated to serve customer needs first and meet water release requirements for high-priority uses.

characteristic. Three of the four reasons, i.e. flexibility, cost, and reliability, are directly influenced by institutional arrangements pertaining to energy and power contracts.

Hoover power contracts protect the customers' ability to dynamically schedule generation and use prescheduled generation for ancillary services. This provision is immensely valuable to customers especially as changes in the electricity sector require them to address grid reliability issues with an increasing frequency and integrate variable renewable generation. Glen Canyon power contracts require customers to send static schedules to WAPA and provide lesser overall flexibility in scheduling generation compared to Hoover; nonetheless, the load following capability of SLCA/IP power is valuable to customers as it allows them to use the other resources in their portfolio in an efficient manner. In the most recent contract negotiations for Hoover and SLCA/IP power, the resale prohibition provision—which prevented customers from reselling or exchanging their hydropower allocation with non-preference customers—was modified to allow customers to utilize their capacity and/or energy in RTOs, ISO, and bulk power markets. This contract modification has further enhanced the value of hydropower for customers. This is particularly so for Hoover power customers that can now capitalize on the opportunity to use the flexibility in hydropower generation and availability of ancillary services—that are in high demand—in a market environment that values these services. The ability of Glen Canyon power customers to use their hydropower allocation in ISOs and bulk power market, even with WAPA exploring the possibility of joining the Southwest Power Pool RTO, will however be limited by the constraints imposed by water and environmental laws and power contracts on dam operations and scheduling generation.

With respect to cost, historic institutional arrangements pertaining to energy require WAPA to set rates 'at cost'. Even as wholesale electricity markets rates continue to fall due to decline in wholesale natural gas prices, Hoover and SLCA/IP hydropower remains economically competitive due to the 'at cost' principle in setting rates. Even in the case of recent SLCA/IP rate increases, where SLCA/IP rates appear higher than wholesale market rates, this resource remains economically competitive with other generation sources as the SLCA/IP rate is 'bundled', that is it includes the cost of generation and transmission, unlike wholesale market rate that only includes generation.

Hoover and SLCA/IP contracts influence reliability as they are long-term power contracts that change minimally (if at all) over the contract duration. Long-term contracts are valuable to customers as they provide stability in contract terms as well as create certainty in accessing the predetermined hydropower allocation, which is useful from a planning perspective. The most recent contract negotiation increased the value of Hoover and SLCA/IP power to customers by

extending Hoover and SLCA/IP contract durations to the legally allowable maximum term of 50 and 40 years respectively.

Consequently, this paper shows that power customers in the Colorado River Basin continue to invest in Hoover and Glen Canyon hydropower as institutional arrangements pertaining to energy and power contracts maintain and at times enhance the value of hydropower to customers. This insight provides a broader lesson for other federal hydropower plants, that is, the constraints imposed by water and environmental laws on hydropower operations may be counterbalanced by amending provisions in power contracts that maintain or enhance the value of hydropower to customers. Even when hydrological conditions and constraints imposed by water and environmental laws may impact hydropower generation, for example, the value of hydropower to customers can be maintained or enhanced by increasing the flexibility available to customers in how they can *use* this limited resource (such as by allowing them to use the resource in an ISO, RTO, or bulk energy market). It is important to note here that the ability to bring about such changes in power contract provisions, however, may depend on the actual contracting process and rules for other federal hydropower plants and the ability of customers to influence the power contracting process.

Lastly, this paper argued that specific institutional arrangements that produce different outcomes for hydropower generation at Hoover and Glen Canyon Dams, in turn, create different consequences for resource users that depended on this resource either directly (through energy availability and use), or indirectly (through economic interdependence). To this end, the analysis in this paper shows that the consequences of changes in hydropower generation at Hoover and Glen Canyon depend on how specific institutional arrangements tie electricity revenues to irrigation aid and environmental programs, and how the power contracts themselves are set up. For Glen Canyon, the firm energy contracts, coupled with the high dependency of irrigation aid and environmental programs on electricity revenues—which is an outcomes of specific collective-choice level institutional arrangements—creates detrimental conditions for both energy and agricultural users, and environmental programs, in case hydropower generation declines. For Hoover, on the other hand, energy users are not affected to the same degree due to changes in generation due to the contingent nature of power contracts; however, revenues for repayment of Central Arizona Project and the Lower Colorado River Multi-Species Program are affected with lower electricity deliveries to energy users. These finding highlights an important point: in case of federal hydropower projects, where specific institutional arrangements may create a financial dependency of hydropower revenues for other water uses, decisions that cause changes in dam operations will need to consider the consequences of changes in hydropower generation for non-power resource users. Moreover, while this study has identified the types of

impacts on resource users as a result of specific institutional arrangements, the calculation of extent of impact warrants further attention.

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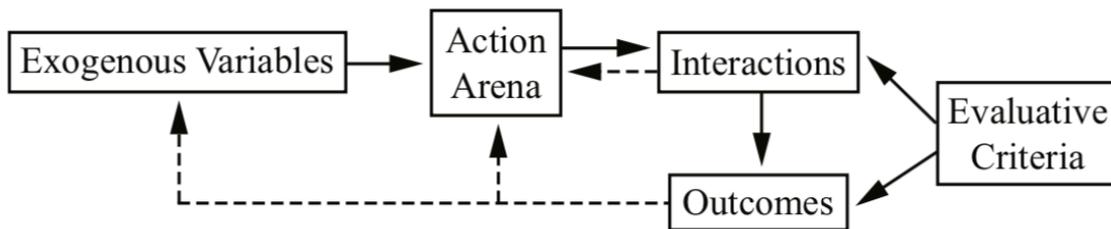
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Appendix A: Overview of the IAD

The IAD Framework has its origins in a general systems approach to policy processes, in which inputs are processed by policymakers into outputs that have outcomes that are evaluated, with feedback effects (McGinnins, 2011). A simple schematic of the IAD framework will look like Figure 10 below.

Figure 10 A Simplified Schematic of the IAD Framework



Source- Ostrom, 2005, p. 13.

Exogenous variables include attributes of the community, nature of the good/biophysical conditions, and rules-in-use, i.e. institutional arrangements, which not only create the context within which decision-making occurs. Action arena (or action situation) is where the decision is made. Outcomes are shaped by exogenous factors and the decisions that are made in the action arena. These outcomes are then evaluated, and can feedback into the exogenous variables, or action arenas, thereby creating changes as desired.

In case of this project, the focus has been on rules (i.e. institutional arrangements), and how they influence dam operations and power marketing, allocation, and resource use in the Colorado River Basin (i.e. action arena) to produce outcomes.

A concise introduction to the key concepts within IAD and Ostrom's project on institutions can be found in McGinnis (2011).

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