The Future of Baseload Renewable Energy: Efforts to Streamline Geothermal and Hydropower Permitting and Regulation

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Abstract

Recent policy trends, such as growing state renewable energy policies and the pending Federal Clean Power Plan, have continuously increased planning and development of renewable energy in the United States. To date, much of this increase has come in the form of variable renewable energy, such as photovoltaic solar and wind. However, as federal and state renewable energy mandates and goals increase, baseload renewable energy technologies, such as hydropower and geothermal may play an important role in the renewable energy generation mix. This paper reviews some of the current and/or recent regulatory barriers faced by the hydropower and geothermal industries as well as policy options and recent statutory, regulatory, and policy initiatives to improve permitting timeframes.

I. Introduction

The United States' energy generation mix is changing and as such transforming the electric power system (grid). Federal and state policies have, in large part, lead to the steady retirement of coal-fired baseload generation and the growth of variable renewable energy resources (VREs).[1] Current state renewable energy policies have predominantly coincided with growth of VREs like wind and photovoltaic (pv) solar, while baseload renewables, such as hydropower and geothermal have seen little or no growth, but may be important to balance VREs and could be a viable replacement to retiring coal-fired baseload plants.[2]

Aggressive state renewable energy policies in states such as California, Hawaii, and Vermont are driving demand for renewable energy development. Hawaii and Vermont[3] both require that the states' retail electricity suppliers obtain 100 percent of their annual electricity sales from eligible renewable sources by 2045 and 2032, respectively.[4] [5] Similarly, California requires that the state's retail electricity suppliers obtain 50 percent of their annual electricity sales from eligible renewable sources.[6] Policies such as these have contributed to over 16 GW of projected solar pv

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[1] *See* U.S. ENERGY INFO. ADMIN., FUTURE POWER SECTOR CARBON DIOXIDE EMISSIONS DEPEND ON THE STATUS OF THE CLEAN POWER PLAN, at 1 (2016), *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=26292. (The U.S. Energy Information Administration (EIA) expects forty-five gigawatts of coal-fired baseload capacity to be retired by the end of 2016. If the EPA's Clean Power Plan (CPP) take effect, the EIA expects another 55 GW of coal plant retirements by 2040, while the EIA expects 20 GW of coal plant retirements by 2040 if the CPP does not take effect.)
[2] *See* U.S. Energy Info. Admin., Electric Power Monthly (June 2016) (listing net generation from renewable sources from 2006-June 2016), *available at* *https://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_01_a*
[3] Act 56 of Jun. 30, 2015, Ch. 30, VT. STAT. 8002 (relating to establishing a renewable energy standard).
[4] HAW. REV. STAT. § 269-91 (2015).
[5] H.B. 623, 28th Leg. (HI. 2015).
[6] CAL. CODE REGS. tit. 15, §§ 25740-25751 (2015).

installations for 2016[7] and 52.31 GW of projected new wind capacity by 2020 in the United States.[8]

The changing energy generation mix in the United States is leading to declining reserve margins and reliability concerns.[9] Operationally, intermittent wind and solar pv create inherent ramps and dips in power output which at times lead to supply and demand imbalances on the grid.[10] In order to balance baseload demand with VREs, system planners are developing additional transmission and relying on energy storage, enhanced forecasting and demand response services.[11] However, these solutions do not address unscheduled flows associated with over generation. Where baseload renewables use existing transmission efficiently because of high capacity factors, VREs often require additional transmission infrastructure to accommodate the same amount of power.[12] In addition, most large-scale energy storage technologies, with the exception of pumped-storage hydropower, remain untested or in limited use in the United States. [13] Increases in VREs have also created indirect costs associated with unscheduled flows. When system operators cannot control unexpected flow they respond by curtailing generation, deploying phase shifters, and cutting transmission.[14] Baseload renewables can help electric system operators avoid additional costs from purchasing and then balancing intermittent power with storage or new transmission.

This paper discusses regulatory and permitting process improvements associated with two of these baseload renewable energy technologies, geothermal and hydropower. Each of these technologies has a longstanding history rooted in statutes dating back forty or more years.[15] However, in order to compete with other energy resources in the 21st century both industries have sought regulatory and policy changes to expedite regulatory approvals required to move forward with project development.

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[7] GREEN TECH MEDIA RESEARCH, U.S. SOLAR MARKET INSIGHT REPORT, at 1 (2016), *available at http://www.greentechmedia.com/research/subscription/u.s.-solar-market-insight.*

[8] U.S. DEPT. OF ENERGY, WIND VISION, http://www.energy.gov/maps/map-projected-growth-wind-industry-now-until-2050 (last visited Sept. 10, 2016).

[9] NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, 2015 LONG-TERM RELIABILITY ASSESSMENT, at 1 (2015), *available at* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf.

[10] NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, 2013 SPECIAL RELIABILITY ASSESSMENT: MAINTAINING BULK POWER SYSTEM RELIABILITY WHILE INTEGRATING VARIABLE ENERGY RESOURCES – CAISO APPROACH, at 2 (2013), *available at* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf.

[11] Benjamin Matek, *The Benefits of Baseload Renewables: A Misunderstood Energy Technology*, 28 THE ELECT. JRNL. 105-108 (2015)

[12] *Id.* at 106.

[13] *Id.* at 106-107*; see also* U.S. ENERGY INFO. ADMIN., LEVELIZED COST AND LEVELIZED AVOIDED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK 2014, at 10-29 (2014) *available at* http://www.eia.gov/forecasts/ aeo/electricity_generation.cfm and Collin Doughty, Linda Kelly, and John Mathias, Bulk Energy Storage in California, 12-16, Energy Assessments Division California Energy Commission (July 2016), *available at http://www.energy.ca.gov/2016publications/CEC-200-2016-006/CEC-200-2016-006.pdf.*

[14] *Id.*

[15] For a history of the geothermal development in the United States *see* U.S. Dept. of Energy, A History of Geothermal Energy in America, http://energy.gov/eere/geothermal/history-geothermal-energy-america. For a history of hydropower development in the United States *see* U.S. Dept. of Energy, History of Hydropower, http://energy.gov/eere/water/history-hydropower.

Section II of this paper discusses geothermal permitting barriers and options for improving permitting efficiency, including:

- Regulatory and policy options designed to streamline geothermal exploration permitting;
- Previously proposed federal legislation designed to streamline geothermal exploration permitting; and
- Techniques for effectively navigating the current federal regulatory framework.

Section III of this paper discusses hydropower permitting barriers and options for improving permitting efficiency, including:

- Enacted federal legislation designed to expedite small hydropower development and development at non-powered dams (NPDs);
- Finalized federal agency regulatory policy designed to expedite development at U.S. Army Corp of Engineers (USACE) NPDs; and
- Currently pending federal legislation designed to improve process efficiency for Federal Energy Regulatory Commission (FERC) hydropower licensing.

II. Geothermal

A. Introduction

Developing geothermal resources for electricity production is a time consuming endeavor, particularly when the project is on federally managed public lands or where the project receives federal funding. In 2014, the National Renewable Energy Laboratory (NREL) analyzed timelines for permitting and environmental review under the National Environmental Policy Act of 1969 (NEPA) for geothermal development on federal lands.[16][17] Under the current federal regulatory framework a geothermal project may require some level of NEPA analysis five or more times over the course of a geothermal project.[18] This includes NEPA analysis during:

- Federal agency land use planning;
- Prior to leasing a nominated parcel;
- Exploration, resource confirmation, and production drilling; and
- Well field and power plant development.

Based on NREL's analysis, the typical geothermal project takes between seven to ten years to develop, which does not include the process of nominating a parcel for geothermal development and a pre-leasing environmental assessment (EA) conducted by the relevant federal land management agency (either the U.S. Bureau of Land Management [BLM] or U. S. Forest Service [USFS]).[19] As a result of the lengthy development timeline, many geothermal projects may suffer from "opportunity loss" or the inability to capitalize on time sensitive policies, such as state renewable portfolio standards (RPS) or early incentives that may be available under the programs

[16] An estimated 90% of geothermal resources in the United States are located on federally managed public lands. See BLM, 2005. "Comprehensive Strategic Plan for Geothermal Management."
[17] Katherine R. Young, Kermit Witherbee, Aaron Levine, Adam Keller, Jeremy Balu, & Mitchell Bennet, Geothermal Permitting and NEPA Timelines, GRC Transactions, Vol. 38, at 893-904 (2014).
[18] *Id.* at 894.
[19] *Id.*

like the proposed federal Clean Power Plan's Clean Energy Incentive Program.[20] However, developers have expressed that from a technical standpoint a geothermal project could be developed within as little as three to four years.

This section will review potential regulatory, policy, or legislative changes that could assist with the project development timeline, as well as strategies that may assist developers navigate the current regulatory framework.

B. Regulatory and Policy Changes

Regulatory and/or policy changes could assist the geothermal project development timeline, particularly during the exploration and resource confirmation phase, which is crucial to obtaining financing for the remainder of the project.[21] A geothermal developer seeking to explore areas for geothermal resources is currently limited to two options:

1. A developer may submit a Notice of Intent to Conduct Geothermal Resource Exploration (NOI) under 4 CFR 3251, but is limited to surface exploration (e.g. geophysical exploration such as electrical, magnetotelluric, gravity, or seismic surveys) or the drilling of temperature gradient holes (TGHs) that do not touch the geothermal resource. Both of these types of exploration activities may be eligible for a categorical exclusion from the NEPA process under 516 DM 11.9 so long as the activity does not require temporary or new road construction and does not include any extraordinary circumstances listed in 43 CFR 46.215. An NOI approved using a categorical exclusion typically takes the BLM two to three months.[22]

2. A developer may submit a Geothermal Drilling Permit (GDP) under 43 CFR 3261 for any drilling that touches the geothermal resource (including slim holes and observation wells). Any proposed activity submitted using a GDP must complete the NEPA process, generally through an EA. The EA process for GDPs typically takes around one year to complete.[23]

One policy option to expedite the exploration permitting process could be for the BLM to use its rulemaking authority to create a third category of wells focused on resource confirmation that falls in between the current NOI and GDP processes. A resource confirmation well permit application could conceivably include an environmental review process shorter than the current EA process through either an expansion of the current categorical exclusion applicable to NOIs or an expedited EA process.[24]

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[20] The proposed Clean Energy Incentive Program provides incentives for early Clean Power Plan compliance in 2020 and 2021 for eligible renewable energy resources, including solar, wind, hydropower, and geothermal energy. *See* Clean Energy Incentive Program Design Details, 81 Fed. Reg. 42,940 (June 30, 2016). Note, as of February 9, 2016 the U.S. Supreme Court stayed implementation of the Clean Power Plan (40 CFR Part 60) pending judicial review. *See* Chamber of Commerce, et al. v. EPA, et al. (Feb. 9, 2016), https://www.supremecourt.gov/orders/courtorders/020916zr3_hf5m.pdf.

[21] *See* Bethany Speer & K.R. Young, Assessment of Needs for Further Research to Understand the Role of Governments in Supporting Geothermal Exploration, GRC Transactions, Vol. 40 (forthcoming October 2016).

[22] Young, *supra* note 15, at 899.

[23] *Id.*

[24] A similar policy could expand the current categorical exclusion for TGHs to include a limited amount of surface disturbance for drilling pads and access roads.

A second policy option could be an expansion of the scope of the BLM's pre-leasing environmental review. The BLM typically analyzes its decisions to lease public lands foreseeably containing geothermal resources by completing a broad-scoped EA, which identifies and describes the resources within the leasing area. Leasing EAs also describe the environmental consequences associated with potential indirect and cumulative impacts of the decision to lease the parcel of land. The BLM could expand the scope of leasing EAs to include the analysis necessary to allow approval of exploration or drilling permits with a Determination of NEPA Adequacy (DNA). To accomplish this, the BLM would need to combine NEPA analysis for leasing and exploration into a single EA. The NEPA analysis would encompass leasing and exploration activities requiring approval of an NOI or could expand even further and encompass resource confirmation, which currently requires approval of a GDP. A challenge with this policy option would be determining what areas of the lease parcel to analyze for ground disturbance, especially since this would require identifying areas within the lease parcel where geothermal exploration is likely to occur.

C. Proposed Federal Legislation

Understanding the current barriers to geothermal resource confirmation drilling, in February 2015, Senators Dean Heller (R-NV) and James Risch (R-ID) introduced the Geothermal Exploration Act of 2015.[25] The bill sought to amend the Geothermal Steam Act of 1970 to add a categorical exclusion for certain geothermal exploration test projects.[26] The bill would have provided a categorical exclusion for drilling test or exploration wells on leased land:

- With fewer than five acres of soil or vegetation disruption at each well location as well as fewer than five acres of soil or vegetation disruption for access and egress from the project site.
- With an individual surface disturbance of fewer than five acres if the total surface disturbance is less than 150 acres and a site-specific analysis was previously prepared under NEPA.
- At a location or well pad site at which drilling has occurred in the previous five years before the date of spudding the well.
- In a developed field for which an approved land use plan or NEPA review analyzed drilling as a reasonably foreseeable activity within the previous ten years before spudding the well.[27]

The bill was introduced in the Senate, but never acted upon.

D. Strategies to Navigate the Current Regulatory Process

The above-mentioned policy, regulatory, or legislative changes could have a large impact on reducing upfront development timelines and costs during the crucial resource confirmation phase of a geothermal project. However, without these changes other strategies exist for reducing the overall permitting and development timelines. Notably, combined and tiered NEPA analysis has proven effective for navigating the geothermal permitting process. As discussed in detail in Young et al,[28] developers can conduct a broader and more in-depth NEPA analysis (EA or

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[25] S. 562, 114th Cong. (2015).
[26] *Id.*
[27] *Id.*
[28] Young, *supra* note 15, at 902.

Environmental Impact Statement [EIS]) that analyzes the impacts of multiple phases of geothermal development in a single environmental analysis. After completing the comprehensive upfront analysis, the BLM may utilize DNAs (approximately one month approval time) to approve subsequent drilling or power plant development activities that were initially considered in the comprehensive environmental analysis. For example, the NEPA analysis could include locations of well pads, roads, pipelines, and even a power plant that are not necessary to approve an NOI submitted for temperature gradient holes or GDP submitted for resource confirmation wells. However, this comprehensive analysis would allow for a faster approval when the developer submits subsequent permit applications for resource confirmation wells, production wells or utilization of the resource (i.e. power plant development) so long as no new information or unanticipated environmental impacts require new or supplemental analysis. 516 DM 11.6(B).[29]

III. Hydropower

A. Introduction

The time required to develop a hydropower project varies significantly depending on whether the project requires a license or exemption from the Federal Energy Regulatory Commission (FERC), is developed on a United States Army Corp of Engineers (USACE) or Bureau of Reclamation (Reclamation) facility, or is "non-jurisdictional" under the Hydropower Regulatory Efficiency Act of 2013.[30] Projects requiring a FERC license may vary significantly in the time it takes to obtain a license and other necessary permits to when the project reaches commercial operation. A 2014 U.S. Department of Energy (DOE) Hydropower Market Report examined timelines for sixteen FERC licensed projects and thirteen exempt projects from 2005 to 2013.[31] The report revealed that the median time from license application to commercial operation was roughly sixteen years, while the median time from exemption application to commercial use was roughly 2.5 years.[32] Hydropower development timelines were the longest at non-powered dams (NPDs), where four of the projects took twenty-five years or longer from license application to commercial operation.[33] Lengthy development times at NPDs could be attributed to projects located at USACE facilities, which may require a Section 404 permit under the Clean Water Act and/or a "408 authorization" under Section 14 of the Rivers and Harbors Act before construction may begin. As a result, many hydropower projects may also suffer from opportunity loss, such as the inability to capitalize on state RPS (if applicable to hydropower) or early incentives that may be available under the programs like the proposed federal Clean Power Plan's Clean Energy Incentive Program.[34]

This section reviews recent regulatory and policy changes, as well as proposed legislation aimed at reducing hydropower licensing, permitting and development timelines.

B. Regulatory and/or Policy Changes

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[29] This strategy may benefit project developers confident in the likelihood of success of the geothermal project, but the upfront costs and effort associated with this approach may not benefit smaller developers or developers uncertain in the quality of the geothermal resource.
[30] Hydropower Regulatory Efficiency Act, Pub. L. No. 113-23 (2013).
[31] Rocio Uria-Martinez, Patrick W. O'Connor & Megan M. Johnson, 2014 Hydropower Market Report (2015).
[32] *Id.* at 20.
[33] *Id.*
[34] *See* Clean Energy Incentive Program Design Details, *supra* note 18.

As a result of long development timelines, both Congress and federal agencies have taken considerable steps to make the licensing and permitting process more efficient. In August of 2013, President Obama signed into law the Hydropower Regulatory Efficiency Act of 2013 (Pub. L. No. 113-23), which addressed both small hydropower development and development at NPDs.

i. Small Hydropower Development

The 2013 Act included two provisions to assist small hydropower development.

First, the Act amended subsection (d) of Section 405 of the Public Utility Regulatory Policies Act of 1978 to allow FERC to provide license exemptions to projects up to 10 MW (previously 5 MW).[35]

Second, the Act removed "qualifying conduit hydropower facility[ies]" from FERC licensing jurisdiction under section 30(a) of the Federal Power Act (FPA) (i.e. non-jurisdictional) and replaced the licensing/exemption process with a 60-day Notice of Intent (NOI) process.[36] In order to qualify for the NOI process the facility must:

- Be constructed, operated, or maintained for the generation of electric power and uses for such generation only the hydroelectric potential of a non-federally owned conduit;[37]
- Have an installed capacity that does not exceed 5MW;
- Not be licensed under, or exempted from FERC license requirements on or before August 9, 2013.

In 2015, FERC clarified the scope of qualifying conduit authorizations in *Soldier Canyon Filter Plant*, 151 FERC ¶ 61,228 (2015). In *Soldier Canyon*, FERC considered whether a proposed hydropower project that uses hydroelectric potential in part created by a dam complies with section 30(a) of the FPA.[38] FERC found that a qualifying small conduit facility may be excluded from FERC jurisdiction if it uses the hydropower potential of a dam as long as the project "…is not an *integral part of a dam…*"[39]

FERC reasoned that in analyzing the legislative intent of the 2013 Hydropower Efficiency Act, the "statutory requirements are the same for qualifying conduit hydropower facilities (i.e., those excluded from the licensing requirements of the FPA) and small conduit facilities (i.e., those eligible for an exemption authorization from the Commission)."[40] FERC further reasoned that when promulgating the regulations implementing conduit facility exemptions, FERC defined an exempt facility as one that

[35] Hydropower Regulatory Efficiency Act of 2013, Pub. L. 113-23, § 3 (2013).
[36] *Id.* at § 4.
[37] The term "conduit" means any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity. 16 USC § 823a(a)(3)(A).
[38] The proposed facility would be located on the Soldier Canyon Pipeline, which is connected to a secondary outlet of Horsetooth Reservoir in Fort Collins, Colorado through the Soldier Canyon Dam. *Soldier Canyon Filter Plant*, 151 FERC ¶ 61,228 (2015) at 2-3.
[39] *Soldier Canyon Filter Plant*, 151 FERC ¶ 61,228 (2015) at 3-4.
[40] *Id.* at 4.

> "utilizes for electric power generation the hydroelectric potential of a conduit…is not an *integral part of a dam*; and does not rely on construction of a dam which construction will create any portion of the hydrostatic head that the facility uses for power generation, unless the construction would occur for agricultural, municipal, or industrial consumption purposes even if hydroelectric generating facilities were not installed." [41]

FERC stated that a conduit facility would not be ineligible for an exemption "unless the powerhouse and the dam together form a physically and functionally indivisible unit for the impoundment of water…"[42] FERC further found that the legislative intent underlying conduit exemptions and qualifying conduit authorizations "…to encourage development of power facilities associated with industrial, municipal, or agricultural water supply, where hydroelectric energy can be incidental to the primary purpose of the conduit…" supported Solider Canyon's argument that section 30(a) of the FPA "…does not exclude a hydro facility that uses the hydroelectric potential of a conduit, where the potential is in part created by the elevation of a dammed reservoir from which the conduit collects water, provided however the conduit is non-federally owned."[43]

Based on the sample licensing and exemption timeframes discussed above, the 2013 provisions combined with the Soldier Canyon decision may dramatically decrease the time required to develop small hydropower projects that previously were subject to FERC licensing or exemption from licensing requirements.

ii. Non-Powered Dam Development

The DOE recently released (July 2016) the Hydropower Vision Report summarizing the history of hydropower development in the United States and providing a "Roadmap that defines a range of actions needed to realize the economic and social benefits of increased hydropower in the future."[44]

Among the conclusions in the Hydropower Vision Report, economic modeling analysis completed by NREL using the Regional Energy Deployment System (ReEDS) model estimated that by 2050 roughly 4.8 GW of hydropower can be developed at existing NPDs, with 75% (3.6 GW) at USACE facilities.[45] This roughly aligns with the USACE's own 2013 assessment that placed 2.8 of 6 GW of potential hydropower development at existing USACE NPDs into the economically "feasible capacity" category.[46]

In addition to the small hydropower provisions, the 2013 Hydropower Regulatory Efficiency Act also included a provision to create a pilot program to test a two-year Fast-Track Licensing

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[41] *See* 18 C.F.R. § 4.91(f) (1981), originating in 45 Fed. Reg. 28, 085 (Apr. 28, 1980). The provisions were renumbered over the years, most recently in 2014 (effective February 23, 2015). *See* 18 C.F.R. § 4.30(b)(30).
[42] *Solider Canyon Filter Plant*, 151 FERC ¶ 61,228 (2015) at 5. (citing *Hy Power Energy Co.*, 79 FERC ¶ 61,060, at 61, 273 n.6 (1997)).
[43] *Id.* at 3, 5.
[44] U.S. Dept. of Energy Wind and Water Power Technologies Office, Hydropower Vision: A New Chapter for America's 1st Renewable Electricity Source (2016).
[45] *Id.* at 273.
[46] Hydropower Analysis Center for USACE Headquarters, Hydropower Resource Assessment at Non-Powered USACE Sites (2013).

process at NPDs.[47] In August of 2014, FERC approved the use of the pilot program at the Kentucky River Lock & Dam No. 11 Hydroelectric Project a 5 MW project located on the Kentucky River.[48] On May 5, 2016 FERC issued a license for the project, marking the first successful completion of the two-year pilot program.[49]

More recently, in July of 2016 the USACE and FERC finalized a new MOU facilitated by the DOE to better align FERC licensing with the USACE's 404 and 408 processes.[50] Broadly, the MOU establishes a commitment from both agencies to provide early initiation review during the pre-filing scoping and study determination phase, establish a schedule, meet with prospective applicants, share data, and collaborate in the NEPA process, with FERC acting as lead agency.[51] More specifically, the MOU establishes a new two-phased approach for synchronizing the USACE and FERC processes. In phase one, FERC and USACE will conduct the environmental review for the FERC license and 404 and 408 processes, which results in a FERC license and status letters on the 404 permit and 408 environmental review.[52] In phase two, FERC, the USACE 408 program, and the developer will work to review the status of design and safety elements of the NPD project and determined design steps and a schedule necessary to secure a 408 approval and FERC approval of the design for construction.[53] Once the agencies approve phase two, the USACE signs off on a final 404 permit and 408 approval, at which point FERC will authorize construction of the project.[54]

C. Proposed Federal Legislation

In 2015, both the U.S. House of Representatives and Senate introduced bipartisan bills that promote regulatory improvements to hydropower licensing. In September 2015, the Senate Energy and Natural Resources Committee's Chairwoman, Lisa Murkowski (R-Alaska), introduced S.2012, the Energy Policy Modernization Act of 2015. In November 2015, the House Committee on Energy and Commerce's Fred Upton (R-Michigan) introduced H.R.8, the North American Energy Security and Infrastructure Act of 2015. Both S. 2012 and H.R. 8 are broad energy bills with provisions promoting hydropower development through licensing and regulatory efficiency. As of September 8, 2016 the U.S. House of Representatives and Senate are in conference committee to resolve differences on the two versions of the bill.[55] This section briefly discusses some of the bills' major hydropower provisions.

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[47] *See* Hydropower Regulatory Efficiency Act § 6.
[48] Federal Energy Regulatory Commission, Authorization to Test a Two-Year Licensing Process for the KY River Lock & Dam No. 11 Hydroelectric Project (2014), https://www.ferc.gov/media/news-releases/2014/2014-3/P-14276.pdf.
[49] Michael Harris, FERC Issues First Hydropower Plant License Under New Two-Year Process, Hydro World (May 12, 2016), http://www.hydroworld.com/articles/2016/05/ferc-issues-first-hydropower-plant-license-under-new-two-year-process.html.
[50] Memorandum of Understanding Between the United States Army Corps of Engineers and the Federal Energy Regulatory Commission on Non-Federal Hydropower Projects (2016), *available at* http://www.ferc.gov/legal/mou/2016/07-21-16.pdf.
[51] *Id.*
[52] *Id.* at Attachment A p. 5-12.
[53] *Id.* at Attachment A p. 13-15.
[54] *Id.* at 15.
[55] *See* U.S. SENATE COMMITTEE ON ENERGY & NATURAL RESOURCES NEWSROOM, MURKOWSKI: THIS IS OUR CHANCE TO MODERNIZE OUR ENERGY POLICY, *available at* http://www.energy.senate.gov/public/index.cfm/republican-news?ID=644C390D-66E5-454F-8BEC-B43BC39DC286.

Hydropower Licensing and Process Improvements/Judicial Review of Delayed Federal Authorization

H.R. 8 and S. 2012 both focus on hydropower licensing and process improvements. Both bills would amend the FPA by designating FERC as the lead agency to set a binding schedule and coordinate all applicable federal authorizations, including NEPA review, in order to address permitting backlog.[56] H.R. 8 specifies that "…any Federal, state, or local government agency or Indian tribe that does not complete its disposition of a Federal authorization by the deadline set by FERC may file for an extension…" with the appropriate U.S. Court of Appeals.[57] If the court denies the extension, FERC and the hydropower applicant may move forwarded with the proposed authorization process.[58] In contrast, S. 2012 allows FERC to refer interagency disputes, including failure to comply with the deadline set by FERC, to the Council on Environmental Quality.[59]

License Study Improvements

Both H.R. 8 and S. 2012 direct FERC and other resource agencies to standardize best practices in licensing procedures using existing, reliable studies and information where appropriate. H.R. 8 requires "…FERC to establish a program to develop comprehensive plans, at the request of the hydropower applicant, on a regional or basin-wide basis, in consultation…" with relevant stakeholders.[60] However, S. 2012 only directs FERC to establish a voluntary pilot program covering at least one region to consider a region-wide approach to hydropower licensing.[61]

Closed-loop Pumped Storage Projects

H.R. 8 addresses development of closed-loop pumped storage projects[62] by establishing an expedited licensing process that eliminates FERC's conditioning authority under 4(e), 10(g), and 10(j) of the FPA.[63] While S. 2012 promotes the development of pumped storage, generally, by directing FERC to initiate a proceeding to "…identify and determine the market, procurement, and cost recovery mechanisms that would encourage development of pumped storage hydropower assets."[64]

NPD Development

H.R. 8 addresses development of new hydropower at existing NPDs by authorizing FERC to issue a new exemption. To qualify for an exemption, a new hydropower facility must be located

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[56] H.R. 8, 114th Cong. § 1203 (2015); S. 2012, 114th Cong. § 3001 (2015).
[57] H.R. 8, 114th Cong. § 1204 (2015).
[58] *Id.*
[59] S. 2012, 114th Cong. § 3001 (2015).
[60] H.R. 8, 114th Cong. § 1205 (2015).
[61] S. 2012, 114th Cong. § 3001 (2015).
[62] H.R. 8 defines "closed-loop pumped storage projects" as "…a project in which the upper and lower reservoirs do not impound or directly withdraw water from navigable waters; or that is not continuously connected to a naturally flowing water feature." H.R. 8, 114th Cong. § 1206 (2015).
[63] H.R. 8, 114th Cong. § 1206 (2015). (Section 4(e) of the FPA authorizes federal land managers to impose mandatory conditions on a FERC license for hydropower projects located on federal reservations, while sections 10(g) and 10(j) require FERC to consider state and federal resource agencies fish and wildlife recommendations).
[64] S. 2012, 114th Cong. § 10351 (2015).

at an existing NPD or similar infrastructure and must not, at minimum, materially change release operations of an existing NPD or other infrastructure.[65]

III. Conclusion

In order for geothermal and hydropower to compete in the current energy market and avoid opportunity loss, regulatory approval timelines must improve from historic numbers. The geothermal industry, including the Geothermal Energy Association has recognized this, but to date no federal legislation or rulemaking has taken place to expedite geothermal exploration permitting. While certain geothermal projects may benefit from current strategies designed to streamline NEPA approval and permitting, others still wait for an expedited exploration process in order to obtain financing agreements.

In contrast, the hydropower industry has not only recognized the need to expedite licensing and permitting for hydropower development, but has successfully lobbied Congress and regulatory agencies to enact significant federal legislation and finalize federal agency policy aimed to improve hydropower development timelines for small hydropower and NPD projects, with additional proposed legislation to improve general FERC licensing timelines currently in conference committee between the U.S. House of Representatives and Senate. Time will tell whether these strategies will provide the improvement needed for hydropower to compete in the U.S. energy market moving forward.

[65] H.R. 8, 114th Cong. § 1208 (2015).