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Alan Douglass
Regulatory Compliance Manager

May 11, 2023

Via Electronic Filing

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Turners Falls Hydroelectric Project (FERC No. 1889), FirstLight MA Hydro LLC, Northfield Mountain Pumped Storage Project (FERC No. 2485), Northfield Mountain LLC, Response to FERC Additional Information Requests

Dear Secretary Bose:

On March 31, 2023, FirstLight MA Hydro LLC, owner and operator of the Turners Falls Hydroelectric Project ("Turners Falls Project") and Northfield Mountain LLC, owner and operator of the Northfield Mountain Pumped Storage Project ("Northfield Mountain Project") (collectively, "FirstLight"), filed with the Federal Energy Regulatory Commission ("FERC") a Flows and Fish Passage Settlement Agreement for the relicensing of the Turners Falls Project and Northfield Mountain Project (together, "Projects").

On April 26, 2023, relative to the Turners Falls Project, FERC requested FirstLight to address eight[1] additional information requests ("AIRs") relative to the Flows and Fish Passage Settlement Agreement. Also, on April 26, 2023, relative to the Northfield Mountain Project, FERC requested FirstLight to provide an estimate of the cost of each proposed measure in the Flows and Fish Passage Settlement Agreement, including the capital costs, annual operation and maintenance costs, and change in the annual energy production.

Please find attached responses to the Turners Falls Project and Northfield Mountain Project AIRs.

If there are any questions regarding the attached responses, please feel free to contact me at the number above or at alan.douglass@firstlightpower.com.

Respectfully,

Alan J. Douglass

Alan Douglass
Regulatory Compliance Manager

Enclosures: AIR Responses for Turners Falls and Northfield Mountain Projects, BSTEM Supplemental Modeling Report

[1]Schedule A of FERC's letter includes eight AIRs, but the numbering was inadvertently off (AIR No. 2 was missing).

AIR No. 1:

The settlement agreement describes twenty operational and environmental measures in proposed license articles for the Turners Falls Project (i.e., Articles A100 through A410). The settlement agreement does not provide a cost for the measures. Please provide an estimate of the cost of each proposed measure, including the capital cost, annual operation and maintenance cost, and change in the annual energy production (both kilowatt-hours and dollars, if any).

AIR No. 1 Response:

Station No. 1 Upgrades

To maintain future operations under the Flows and Fish Passage Settlement Agreement ("SA") and maintain bypass flows to facilitate fish passage, FirstLight will need to automate the Station No. 1 units, within 3 years of license issuance, such that they are capable of being operated remotely and over a range of flows. The capital costs to automate the units, in 2022 dollars, is shown in Table AIR1-1. Periodic costs and annual operation and maintenance costs are not provided since these are sunk costs associated with operating Station No. 1.

Fish Passage Costs

The fish passage measures included in the SA include for upstream passage the Spillway Lift, two Temporary Eel Passage Structures, two Permanent Eel Passage Structures, and Rehabilitation of the Gatehouse Trapping facility and for downstream passage the Turners Falls Dam Plunge Pool, Station No. 1 Bar Rack, and Cabot Station Rack and Downstream Conveyance. Once the above fish passage measures are constructed and operational, the SA requires FirstLight to conduct fish passage effectiveness testing to determine if the agency fish passage performance standards are achieved. If the performance standards are not achieved, the SA requires FirstLight to consult with the federal and state agencies and implement various adaptive management measures ("AMMs"). Once those AMMs are implemented, fish passage effectiveness testing will be conducted again to determine if the AMM(s) achieved the fish passage performance standards. As explained in the SA, there are multiple rounds of effectiveness testing should performance standards not be achieved. Some AMMs include modifications to operations, while other AMMs require constructing new fish passage measures.

For purposes of responding to this Additional Information Request ("AIR"), FirstLight has included the capital costs, periodic costs[2], annual operation and maintenance costs, and effectiveness testing costs[3] in Table AIR1-1 using the same tabular format as in Exhibit D of the Amended Final License Application ("AFLA"). Table AIR1-1 costs are in 2022 dollars and are based on a 50-year license term. Cost expenditures over the 50-year license term have not been adjusted for inflation but are based on 2022 dollars consistent with FERC's approach for quantifying project economics (Mead Corporation, 1995).[4]

It is unknown if any, some, or all of the AMMs will be implemented as it is dependent on the effectiveness testing results relative to the fish passage performance standards. FirstLight did not estimate the cost of all the AMMs, because of the uncertainty associated with certain AMM's actual design, but did include some of the costlier ones in Table AIR1-1. These include AMMs to increase upstream fish passage performance, if needed, including installing ultrasound arrays in the Cabot Station and Station No. 1 tailraces, and

[2]Periodic costs are capital costs incurred over a 50-year license term.
[3]The effectiveness testing costs assumes all rounds of testing are needed as discussed in the SA.
[4] FERC, Order Issuing New License, Mead Corporation, Project No. 2506, July 13, 1995, p. 8.

creating a zone of passage around Rawson Island located in the bypass reach. For these three AMMs, only the capital cost is provided. The costs not included are generally smaller costs that do not weigh significantly into the evaluation of the AMMs.

Energy Impacts

Future operations under the SA will reduce generation at the Turners Falls Hydroelectric Project due to maintaining higher bypass flows, Cabot Station ramping requirements, maintaining variable flow releases for recreational boating, maintaining a stabilized flow regime from Cabot Station, and limiting the rate of rise in water levels in the Turners Falls Impoundment ("TFI") as measured at the dam. The operating conditions in the SA, with the exception of "flex" operations and variable flows[5], and baseline conditions were simulated in the hourly time step operations model for the period 1932-2002. Table AIR1-2, below, is a summary of the average annual generation under baseline conditions, SA conditions, and the difference.

Table AIR1-1: Turners Falls Hydroelectric Project: Average (1962-2003) Annual Generation Loss under Settlement Agreement

Average Annual Generation under Baseline Conditions (MWh/year)	Average Annual Generation under Settlement Agreement (MWh/year)	Loss in Average Annual Generation under Settlement Agreement versus Baseline Conditions (MWh/year)
296,754	260,082	36,672

Operating the Turners Falls Hydroelectric Project per the SA results in an average annual generation loss of approximately 36,672 MWh/year, or 12.4%. In 2022, the Turners Falls Hydroelectric Project had a realized energy value of $71.61/MWh (this is a realized value calculated as revenue divided by generation). Thus, a loss of 36,672 MWh/year equates to a loss of $2,626,218/year or $131,310,910 over a 50-year license term ($2,626,218 x 50 years= $131,310,910).

AIR No. 2:

The settlement agreement explains that FirstLight would calculate naturally routed flow ("NRF") for the period of December 1 through June 30 as the hourly sum of the discharges from 12 hours previous as reported by the Vernon Hydroelectric Project No. 1904, Ashuelot River United States Geological Survey (USGS) Gauge No. 01161000, and Millers River USGS Gauge No. 01166500. FirstLight would calculate the NRF for the period of July 1 through November 30 as the hourly sum of the discharges averaged from 1 to 12 hours previous as reported by the Vernon Hydroelectric Project, Ashuelot River USGS gauge, and Millers River USGS gauge. Please provide formulas and example calculations for the NRF for each time period.

AIR No. 2 Response:

Example calculations of the Naturally Routed Flow ("NRF") for the period December 1 through June 30 and from July 1 through November 30 are shown in Table AIR2-1 at the end of this response.

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[5]See response to AIR No. 8. The energy results below assumed the whitewater boating schedule in the AIP, and not the variable flow releases from the Turners Falls Dam and below Station No. 1; however, all boating flows are an "or Naturally Routed Flow, whichever is less basis" and have a similar number of releases. The energy results are not expected to change based on this minor difference.

AIR No. 3:

Table 1 of the Explanatory Statement and the table on page A-3 of Appendix A of the Settlement Agreement indicate that the total minimum flow below Station No. 1 "shall be the NRF or 90% of the NRF" under certain flow conditions from July 1 through December 31. Please explain the process that FirstLight would use to select whether the minimum flow would be NRF or 90% of the NRF.

AIR No. 3 Response:

The key factor FirstLight will evaluate on whether to pass the NRF, or 90% of the NRF, is the TFI elevation. FirstLight may need to retain 10% of the NRF to help build the TFI water level.

AIR No. 4:

On page A-4 of Appendix A, FirstLight states: "If the Station No. 1 units are used to maintain the Total Minimum Bypass Flow below Station No. 1, and if some or all of the Station No. 1 units become inoperable, the balance of the flow needed to maintain the Total Bypass flow below Station No. 1 will be provided from either the Turners Falls Dam Minimum Flow (dam or canal gate), Fall River, Turners Falls Hydro, LLC or Milton Hilton, LLC." Flow releases from the Fall River, Turners Falls Hydro, LLC, and Milton Hilton, LLC appear to be outside the control of FirstLight, and it is unclear how FirstLight would use flow releases from these sources to provide the proposed minimum flow, in the event the Station No. 1 units become inoperable. For each source, please specify: (1) the location of the flow release; (2) any procedures that FirstLight would use to measure and monitor changes in the flow release (including the type, location, and accuracy of any monitoring equipment and gages); and (3) any written agreements between FirstLight and Turners Falls Hydro, LLC or Milton Hilton, LLC, to release minimum flows from the locations specified in item 1 above. In addition, please specify any procedures that FirstLight would use to adjust flows from other sources (i.e., the Turners Falls Dam), as needed to maintain compliance with the proposed minimum flow.

AIR No. 4 Response:

FirstLight included the option of maintaining the Total Minimum Bypass Flow below Station No. 1 not only from Station No. 1 discharge or Turners Falls Dam spill, but from the Fall River or discharges from the Turners Falls Hydro, LLC[6] and Milton Hilton, LLC. Figure AIR4-1 shows the location of the Fall River confluence with the Connecticut River, and the Turners Falls Hydro, LLC and Milton Hilton, LLC discharge locations. FirstLight does not have specific details on how it will measure and monitor changes in flow at these three locations. At this juncture, FirstLight proposes to maintain the Total Minimum Bypass Flow below Station No. 1 via Station No. 1 generation and/or Turners Falls Dam discharge. FirstLight will conduct further evaluations to determine if monitoring these sources of flow is feasible and cost effective. FirstLight would also need to consult with the owners of Turners Falls Hydro, LLC and Milton Hilton, LLC to determine how project discharge data could be obtained; there are no current written agreements with these entities to release flow. If FirstLight determines it is feasible to quantify the flow from these three sources in the future it would seek to amend the FERC license accordingly.

[6] Turners Falls Hydro, LLC, FERC Project No. 2622, received a new license on February 25, 2021. On September 1, 2021, the Licensee filed, for Commission approval, its Operations Monitoring Plan. In its monitoring plan, the Licensee indicated it will provide real-time operations data, including project discharge data, from its programmable logic controller.

AIR No. 5:

Tables 3 and 4 of the Explanatory Statement and the tables on page A-5 of Appendix A indicate that the Cabot Station ramping rate would be 2,300 cubic feet per second (cfs), per hour. To evaluate the effects of the proposed ramping rate on aquatic resources, please clarify whether the ramping rate would be uniform across the hour, or if the ramping rate would change over the course of the hour.

AIR No. 5 Response:

The ramping rate would not be uniform across the hour. FirstLight would bring the unit online within approximately 5 minutes, and then flow would be fairly steady for the remainder of the hour. If enough flow is present to support another unit coming online, it would follow a similar pattern at the top of the next hour.

AIR No. 6:

The description of license article A140 in the Explanatory Statement states: "The Cabot Station ramping rates above are intended to take precedence over the flow stabilization requirements below Cabot Station in Proposed License Article A150." However, license article A140 in Appendix A states: "The Cabot Station Ramping Rates above will take precedence over the Flow Stabilization below Cabot Station (Article A160)." Please rectify the inconsistent license article references in the Explanatory Statement and Appendix A.

AIR No. 6 Response:

The license article referenced in the Explanatory Statement is incorrect. It should read "The Cabot Station ramping rates above are intended to take precedence over the flow stabilization requirements below Cabot Station in Proposed License Article **A160**." License Article A140 in Appendix A is correct.

AIR No. 7:

Proposed license article A150 states that FirstLight would provide "Variable Releases from Turners Falls Dam" (defined in the table/notes on page A-6) and a "Variable Flow below Station No. 1" (defined in the table/notes on page A-7) for recreation and ecological conservation. Please clarify whether or not the "Variable Flow below Station No. 1" would be released from Station No. 1 and/or other release points. Please also clarify whether or not variable flows could be released simultaneously from Station No. 1 and Turners Falls Dam, such that the cumulative downstream flow would be 6,500 cfs, or the NRF, whichever is less.

AIR No. 7 Response:

The Variable Flow below Station No. 1 could be comprised of various sources of flow above Station No. 1 including Turners Falls Dam spill, Station No. 1 discharges, Fall River flow, Turners Falls Hydro, LLC discharges and Milton Hilton Hydro, LLC discharges. Similar to FirstLight's response to AIR No. 4, FirstLight proposes to maintain the Variable Flow below Station No. 1 from flow sources it controls including Station No. 1 discharges or Turners Falls Dam spill. Also, as noted in its response to AIR No. 4, if FirstLight determines it is feasible to monitor these other sources of flow, it will seek to amend the FERC license accordingly.

The variable flow release from Turners Falls Dam and the variable flow below Station No. 1 will not occur simultaneously. However, during the variable flow release from Turners Falls Dam, if sufficient NRF is available, FirstLight may operate Station No. 1.

AIR No. 8:

In the description of proposed license article A160 in the Explanatory Statement, FirstLight states that it used its operations model to simulate the proposed flow stabilization operation, to determine whether the proposed operation would increase erosion on the shoreline of the Turners Falls Project impoundment. Please file the output of the modeling, and any report associated with the modeling.

AIR No. 8 Response:

FirstLight used its operations model (software: HEC-ResSim) to simulate the operating conditions in its Flows and Fish Passage Agreement in Principle ("F/F AIP"), with modifications to the definition of the NRF consistent with the SA, and in its Whitewater AIP ("WW AIP"), which is slightly different than the SA as expanded upon below. Hereinafter, for purposes of this response these operating conditions are collectively referred to as the AIP model run.

Output from the AIP model run was used as input into the TFI hydraulic model (software: HEC-RAS). Finally, output from TFI hydraulic model was used as input into the erosion model (software: BSTEM-Dynamic). The BSTEM modeling results were used to prepare a report entitled "*Supplemental BSTEM Modeling Report*", which includes the model output results in the form of figures from BSTEM.[7] The report is included in this FERC filing.

There are some differences between the AIP model run and the SA as follows:

- The Minimum Flow below Turners Falls Dam from 7/1-11/15 is 500 cfs under the SA and 400 cfs[8] under the AIP, and both minimum flows are on an "or NRF, whichever is less" basis.

- The SA includes Draft License Article A150, Variables Releases from Turners Falls Dam and Variable Flow below Station No. 1, while the AIP was based on the whitewater flow release schedule; however, the schedules were similar. In both cases, all flow releases from the Turners Falls Dam or below Station No. 1 were for 4 hours, were on a NRF, or inflow, whichever is less basis, and occurred between July 1 and October 31. Relative to the Turners Falls Dam releases, under the SA there are 10-11 days of 4,000 cfs releases versus 9 days of 5,000 cfs under the AIP. Relative to the flows below Station No. 1, under the SA there are 14 days of flow versus approximately 23 days under the AIP; however, both flows were the same magnitude.

Modeling these differences would not be expected to alter the fundamental findings of the BSTEM analysis under baseline, AFLA, and AIP operating conditions, that high flows are the dominant cause of erosion in the TFI and not Project operations. Note that repeating the three-part modeling steps above to simulate the operating conditions in the SA would be a substantial expense and would require 3-4 months to complete.

[7] The F/F AIP did not include whitewater releases. The operating conditions in the F/F AIP, WW AIP and modifications to the definition of the NRF consistent with the SA (collectively the AIP model run) are reflected in the Supplemental BSTEM Modeling Report.

[8] Technically the F/F AIP was 250 cfs, but FirstLight simulated 400 cfs for this period as it was considered the potential upper boundary.

Table AIR1-1. Costs Associated with Protection, Mitigation and Enhancement Measures at the Turners Falls Hydroelectric Project based on the Flows and Fish Passage Settlement Agreement

PME Measure	Capital Costs of 50 Year License Term (2022 dollars)	Periodic Capital Costs over 50 Year License Term (2022 dollars)	Annual Operation & Maintenance Costs over 50 year License Term (2022 dollars)	[1]Effectiveness Testing Costs over 50 Year License Term (2022 dollars)	[2]Average Annual Costs over 50 Years (2022 dollars)
Project Modifications					
Station No. 1 Upgrades	$1,371,567	$0	$0	$0	$27,431
Fish Passage Facilities					
Spillway Lift	$13,072,174	$1,926,251	$17,329,746	$1,500,000	$676,563
Interim Eel Passage Structures (2)	$0	$0	$100,100	$0	$2,002
Permanent Eel Passage Structures (2)	$282,314	$272,256	$325,633	$100,000	$19,604
Rehabilitate Gatehouse Trapping Facility	$28,574	$0	$0	$0	$571
Turners Falls Dam Plunge Pool	$4,278,145	$552,970	$3,648,368	$666,667	$182,923
Station No. 1 Bar Rack	$3,624,000	$731,731	$268,598	$666,667	$105,820
Cabot Rack and Downstream Conveyance	$4,422,937	$1,205,700	$324,300	$666,667	$132,392
[3]Fish Passage Adaptive Management Measures					
Cabot Tailrace- Ultrasound Array Behavioral	$1,494,516	$0	$0	$0	$29,890
Rawson Island- Create Zone of Passage	$4,188,994	$0	$0	$0	$83,780
Station No. 1 Ultrasound Array Behavioral Barrier	$1,494,516	$0	$0	$0	$29,890
Total	$34,257,739	$4,688,908	$21,996,745	$3,600,000	$1,290,868

Notes:

[1]Three years of effectiveness testing is conducted after implementing the fish passage measures or Adaptive Management Measure per the Flows and Fish Passage Settlement Agreement.

[2]Average Annual Cost= (Total Capital Costs + Periodic Costs + Annual O&M Costs + Effectiveness Study Costs)/50 years

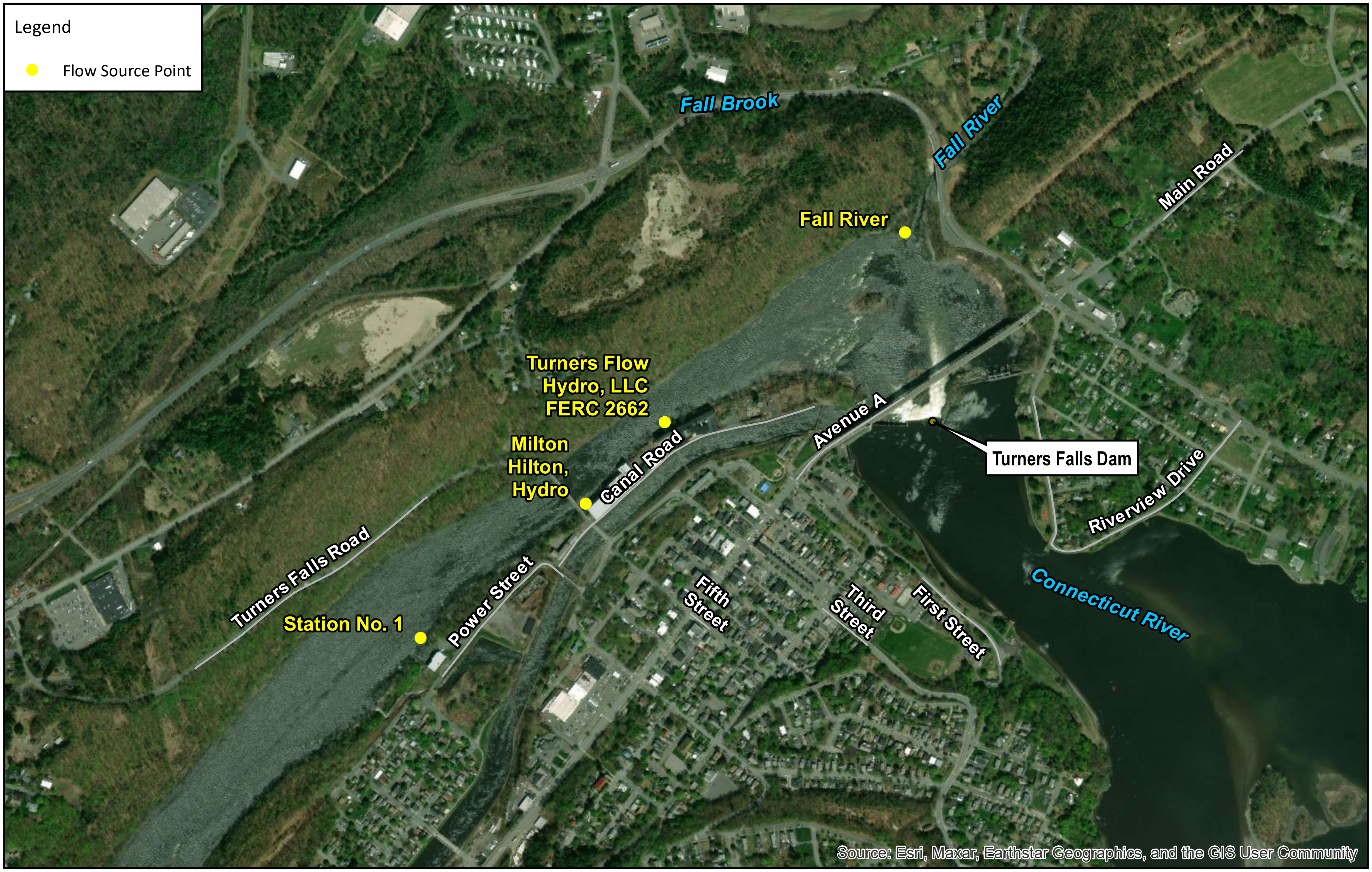
[3]Note that not all of the Fish Passage Adaptive Management Measures are included herein, and the periodic, annual O&M, and effectiveness study costs were not estimated.

All costs expendiures in Table AIR1-1 over the 50-year license term have not been adjusted for inflation, but are based on 2022 dollars.

Table AIR2-1. Example Calculations of the Naturally Routed Flow from Dec 1 to Jun 30 and Jul 1 to Nov 30
(Note: the flow numbers below are fictitious and were used only to demonstrate how the Naturally Routed Flow would be computed.)

Hour of Day	Vernon Discharge (cfs)	Ashuelot River USGS Gage Flow (cfs)	Millers River USGS Gage Flow (cfs)	Total Flow (cfs)	Calculated Naturally Routed Flow from Dec 1 to Jun 30 (cfs)	Comments	Calculated Naturally Routed Flow from July 1 to Nov 30 (cfs)	Comments
1:00 AM	10,000	100	10	10,110	-		-	
2:00 AM	10,000	100	11	10,111	-		-	
3:00 AM	10,000	100	12	10,112	-		-	
4:00 AM	10,000	100	13	10,113	-		-	
5:00 AM	10,000	100	14	10,114	-		-	
6:00 AM	10,000	100	15	10,115	-		-	
7:00 AM	10,000	100	16	10,116	-		-	
8:00 AM	10,000	100	17	10,117	-		-	
9:00 AM	10,000	100	18	10,118	-		-	
10:00 AM	10,000	100	19	10,119	-		-	
11:00 AM	10,000	100	20	10,120	-		-	
12:00 PM	10,000	100	21	10,121	-		-	
1:00 PM	10,000	100	22	10,122	10,110	same as 1:00 AM	10,116	Average of Hrs 1:00 AM to 12:00 PM
2:00 PM	10,000	100	23	10,123	10,111	same as 2:00 AM	10,117	Average of Hrs 2:00 AM to 1:00 PM
3:00 PM	10,000	100	24	10,124	10,112	same as 3:00 AM	10,118	Average of Hrs 3:00 AM to 2:00 PM
4:00 PM	10,000	100	25	10,125	10,113	same as 4:00 AM	10,119	Average of Hrs 4:00 AM to 3:00 PM
5:00 PM	10,000	100	26	10,126	10,114	same as 5:00 AM	10,120	Average of Hrs 5:00 AM to 4:00 PM
6:00 PM	10,000	100	27	10,127	10,115	same as 6:00 AM	10,121	Average of Hrs 6:00 AM to 5:00 PM
7:00 PM	10,000	100	28	10,128	10,116	same as 7:00 AM	10,122	Average of Hrs 7:00 AM to 6:00 PM
8:00 PM	10,000	100	29	10,129	10,117	same as 8:00 AM	10,123	Average of Hrs 8:00 AM to 7:00 PM
9:00 PM	10,000	100	30	10,130	10,118	same as 9:00 AM	10,124	Average of Hrs 9:00 AM to 8:00 PM
10:00 PM	10,000	100	31	10,131	10,119	same as 10:00 AM	10,125	Average of Hrs 10:00 AM to 9:00 PM
11:00 PM	10,000	100	32	10,132	10,120	same as 11:00 AM	10,126	Average of Hrs 11:00 AM to 10:00 PM
12:00 AM	10,000	100	33	10,133	10,121	same as 12:00 PM	10,127	Average of Hrs 12:00 PM to 11:00 PM

Figure AIR 4-1: Location of Flow Sources above Station No. 1



FIRSTLIGHT HYDRO GENERATING COMPANY
Northfield Mountain Pumped Storage Project No. 2485
Turners Falls Hydroelectric Project No. 1889

Response to FERC AIR

Figure AIR 4-1:
Location of Flow Sources
above Station No. 1

Path: D:\FirstLight\GIS\maps\ferc air\figure_AIR_4-1.mxd

AIR No. 1:

The settlement agreement describes eight operational and environmental measures in proposed license articles for the project (i.e., Articles B100 through B310). The settlement agreement does not provide a cost for the measures. Please provide an estimate of the cost of each proposed measure, including the capital cost, annual operation and maintenance cost, and change in the annual energy production (both kilowatt-hours and dollars, if any).

AIR No. 1 Response:

Fish Passage Costs

The fish passage measure included in the SA includes the installation of a barrier net in the Northfield Mountain Project tailrace/intake. Once the barrier net is installed and operational, the SA requires FirstLight to conduct fish passage effectiveness testing to determine if the agency fish passage performance standards are achieved. If the performance standards are not achieved, the SA requires FirstLight to consult with the federal and state agencies and implement various AMMs. Once those AMMs are implemented, fish passage effectiveness testing will be conducted again to determine if the AMM(s) achieved the fish passage performance standards. As explained in the SA, there are multiple rounds of effectiveness testing should performance standards not be achieved. The costs associated with any effectiveness testing has been included under the Turners Falls Fall Hydroelectric Project because the barrier net would be tested simultaneous to testing of fish passage facilities at Turners Falls.

For purposes of responding to this AIR, FirstLight has included the capital cost, periodic costs, and annual operation and maintenance costs in Table AIR1-1 using the same tabular format as in Exhibit D of the AFLA. Table AIR1-1 costs are in 2022 dollars and are based on a 50-year license term. Cost expenditures over the 50-year license term have not been adjusted for inflation but are also based on 2022 dollars.

It is unknown if any, some, or all of the AMMs will be implemented as it is dependent on the effectiveness testing of the barrier net relative to the fish passage performance standards. FirstLight did not estimate the cost of the AMMs and thus, they have not been included in Table AIR1-1.

Energy Impacts

It is not possible to predict, with any certainty, whether increasing the Upper Reservoir storage capacity will result in more or less operation of Northfield Mountain. Northfield Mountain's operation is a function of the cost of the energy to pump and the value of the energy when generating. These values vary hour to hour, day to day, and week to week. Northfield Mountain can use excess renewable energy on the grid to pump, but the timing is difficult to determine with certainty. Therefore, FirstLight developed a sensitivity case in which Northfield generated approximately 54,000 MWhs more than it did using the observed 2009 Northfield Mountain Project pump-generation schedule.

Shown in Table AIR1-2 is the following:

- The average annual generation produced by the Northfield Mountain Project under baseline conditions (2009 observed pump/generation schedule) from the operations model (Column 1 in Table AIR1-2).

- The average annual generation consumed by the Northfield Mountain Project under baseline conditions. The average ratio of pumping (1,189,640 MWh average from 2011-2019) to generating (889,845 MWh average from 2011-2019) is approximately 1.34, meaning it takes 34% more energy to pump than to generate. Thus, the average annual generation was multiplied by 1.34 to estimate the average annual energy consumed for pumping (Column 2 in Table AIR1-2).

- The difference between the average annual generation and average annual pumping is the net generation, which will always be a negative value since more energy is consumed for pumping than generating (Column 3 in Table AIR1-2).

- The same analysis described above for baseline conditions was repeated for the Sensitivity Case, which includes the increased 2009 pump/generation schedule (Columns 4, 5, and 6).

- The difference in average annual generation, generation used for pumping and net generation between baseline conditions and the Sensitivity Case (Columns 7, 8 and 9).

Table AIR1-1. Costs Associated with Protection, Mitigation and Enhancement Measures at the Northfield Mountain Pumped Storage Project based on the Flows and Fish Passage Settlement Agreement

PME Measure	Capital Costs of 50 Year License Term (2022 dollars)	Periodic Capital Costs over 50 Year License Term (2022 dollars)	Annual Operation & Maintenance Costs over 50 year License Term (2022 dollars)	[1]Effectiveness Study Costs over 50 Year License Term (2022 dollars)	[2]Average Annual Costs over 50 Years (2022 dollars)
Fish Passage Facilities					
Barrier Net	$3,823,242	$984,099	$22,027,363	$0	$536,694
Total	$3,823,242	$984,099	$22,027,363	$0	$536,694

[1]The cost of effectiveness testing is included in the Turners Falls Hydroelectric Project estimate.

[2]Average Annual Cost= (Total Capital Costs + Periodic Costs + Annual O&M Costs + Effectiveness Study Costs)/50 years

All costs expendiures in Table AIR1-1 over the 50-year license term have not been adjusted for inflation, but are based on 2022 dollars.

Table AIR1-2. Average Annual (1962-2003) Annual Generation Impact of Sensitivity Case

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
Average Annual *Baseline Generation* from Operations Model (MWh/year)	Average Annual *Baseline Pumping-* Gen x 1.34 (MWh/year)	Average Annual *Baseline Net Generation* (MWh/year)	Average Annual Sensitivity Case *Generation* from Operations Model (MWh/year)	Average Annual *Sensitivity Case Pumping-* Gen x 1.34 (MWh/year)	Average Annual *Sensitivty Case Net Generation* (MWh/year)	Average Annual Change in *Generation* due to Sensitivity Case (MWh/yr)	Average Annual Change in *Pumping* due to Sensitivity Case (MWh/yr)	Average Annual Net Change in Generation (MWh/year)
938,197	1,257,184	-318,987	992,363	1,329,766	-337,403	54,166	72,582	-18,416
						(Col 4-1)	(Col 5-2)	(Col 6-3)

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Federal Energy Regulatory Commission in these proceedings.

Dated at Washington, DC this 11th day of May, 2023.

/s/ Mealear Tauch
Mealear Tauch
Van Ness Feldman, LLP
1050 Thomas Jefferson Street, NW
Seventh Floor
Washington, DC 20007-3877