Whitefield, Maine

Development, Shoreland Zoning, and Floodplain Management

Application for Permit

Section 3027 Transmission Line (345kV AC)

May 12, 2021

Development, Shoreland Zoning, and Floodplain Management Permit Applications

Section 3027 – 345 kV Overhead Transmission Line

submitted to

Whitefield, Maine

By

Central Maine Power Company
83 Edison Drive, Augusta, Maine 04336

5/12/2021

TOWN OF WHITEFIELD DEVELOPMENT APPLICATION

Read Section 2 "Standards" in the Development Ordinance.
Be prepared to answer questions if they apply to your project.

Owner Information	Applicant Information (if different)
Company Central Maine Power Company	Company
Name Attn: Gerry J Mirabile	Name
Mailing Address 83 Edison Drive Augusta, ME 04336	Mailing Address
Phone 207.242.1682	Phone
Email Gerry.Mirabile@cmpco.com	Email

Whitefield Tax Map # 01, 04, 07, 010, 012, 013, 016 , 019 Lot(s) # 001-061, 004-005,007-007, 007-008, 012-48, 013-022, 19-008, 019-052019-032 Lot Size incomplete on mapping

Existing Property Use (check all that apply)	Proposed Property Use (check all that apply)
☐ Forested	☐ Farm
☒ Farmland	☐ Home
☐ Home	Year-round ☐ Yes ☐ No
Year-round ☐ Yes ☐ No	☐ Business
☐ Business	☐ Industrial
☐ Industrial	☐ Mineral Extraction
☐ Mineral Extraction	☒ Other continues to be CMP-owned transmission line corridor
☒ Other CMP-owned transmission line corridor	

Detailed Description of Proposed Use of Site or Building

A 345kV (AC) overhead transmission line supported by dual wooden pole H-frames is to be constructed within the center of an existing, cleared CMP-owned transmission line corridor in Whitefield from the boundary with the Towns of Alna on the south to Windsor on the north and will be referred to as Section 3027.

Existing Primary Structure on Property	Proposed Structure on Property
☐ Home ☐ Business ☐ Industrial Number of stories Wooden dual pole H-frames and mono poles Height 85 ft and 75 ft Exterior dimensions ______ Setback from road ______ Setback lot line 1 ______ Setback lot line 2 ______ Setback rear lot line ______	☐ Home new building ☐ Home addition ☐ Home garage/accessory ☐ Business - new ☐ Business addition Number of stories Wooden dual pole H-frames Height 85 ft Exterior dimensions ______ Setback from road ______ Setback lot line 1 ______ Setback lot line 2 ______ Setback ~~rear~~ lot line in center of 300 ft wide cleared corridor

What types of garbage will you have?	Is there water to the building?
What types of garbage will you have? NA How do you plan to get rid of it? NA	Is there water to the building? ☐ Yes ☐ No NA Will there be water to the building? ☐ Yes ☐ No If yes, attach a sub-surface wastewater disposal system plan. If no, where are the employees going to the bathroom? portable facilities typical to construction projects

Do any of these apply to your property?	Do any state laws apply to your project?
Do any of these apply to your property? ☐ road easements/rights of way ☐ waste/sanitary waste easement ☐ utility easement ☐ deed restriction ☐ deed covenant ☐ other The transmission line corridor is owned by CMP Attach easements, covenants & applicable permits	Do any state laws apply to your project? ☒ Yes ☐ No Federal laws? ☒ Yes ☐ No Is your property in a shoreland zone? ☒ Yes ☐ No Explain ______ Attach easements, covenants & applicable permits

Driveway Entrance (check all that apply)	Parking
☐ driveway entrance proposed ☐ approval of Road Commissioner attached ☐ 911 address needed ☐ state road entrance required ☐ state road change use required Attach copies of any approval or permits obtained Not Applicable	Number of employees Not Applicable Number of customers/day Not Applicable Describe the area Loading Areas How are materials delivered? Not Applicable How are finished products removed from property? Not Applicable

Can you affirm that you have sufficient financial capacity to complete this development? ☒ Yes ☐ No	When do you propose to start? July 2021 When do you propose to finish? Q3, Q4 2021

Erosion Control

What soil disturbance will be created in the construction of your project?

Soil disturbance will be limited that localized to and necessary for installation of dual-pole wooden H-Frames as displayed on Exihibit 1

How will you manage erosion and sediment?

Best management practices (BMPs) described in detail in Exhibit 7 "Environmental Guidelines for Construction and Maintenance Activities on Transmission Line and Substation Projects" will be implemented, functionally maintained and regularly inspected to manage erosion and sedimentation.

When finished, what amount of the property will be bare, no vegetation on it?

After construction is completed and as described under Section 9.0 Site Restoration Standards of Exhibit 7, work areas will be restore and planted with appropriate seed mixes to establish vegetation so that bare, unstable soils are not present.

Map of Property - attach and show: Please refer to Exhibit 1

☐ map and lot numbers

☒ existing and proposed buildings

☐ measurements of lot lines including road frontage

☒ utility lines and drainage ways

☐ location of sanitary waste facilities NA

☒ location of vehicle access roads, parking and loading areas

☒ distances from proposed buildings to lot lines

☐ names of abutting land owners

☒ existing soil conditions

☒ total acres

☒ rights of way

☒ steep areas, low areas, general lay of the land

☒ proposed and existing landscaping including fencing, shrub lines, etc.

Drawing of Proposed Building-attach w/following	Additional Information
☐ ground floor dimensions ☐ elevation ☐ basic sketch of finished building Not Applicable	Describe any proposed signs and/or outdoor lighting ______ Not Applicable What materials will be stored on site? Not Applicable What chemicals will be stored & used on site? Not Applicable What types of machinery will you be operating? Not Applicable What hours do you expect to be operating? Not Applicable

Are you asking for a waiver of any requirement? ☐ Yes ☒ No If yes, please explain.

____
____
____

I affirm that the information provided on this form or attached to it is true and reflects what I propose to do.

Signed: Gerry J. Miahle ________________ **Dated:** May 12, 2021 ____________

What To Do Next

☒ Call PB Chair to schedule a pre-application meeting the month before you want to submit this application. Call the Town Office (549-5175) for the contact information.

☒ Submit your completed application to the Planning Board at least one week before the meeting. You can do one of these ways:

☒ email it to the PB Chair

☐ make 5 copies and deliver them to the Town Office

Planning Board Use
Date Received: ____________________
Date Reviewed by Planning Board: ____________________
Date Application Accepted as Complete: ____________________

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1.0 INTRODUCTION

Central Maine Power Company ("CMP") proposes to construct Section 3027, a 345 kV transmission line, in Whitefield (the "Project"). Section 3027 will be entirely co-located in an existing CMP-owned transmission line corridor.

The Development Ordinance of the Town of Whitefield (amended Nov. 4, 2014) ("Development Ordinance") applies to "new and/or expanded commercial, industrial, institutional, or residential developments" in Whitefield. The Development Ordinance includes "electrical transmission lines" in the definition of "industrial development." CMP accordingly submits the attached application to the Planning Board for approval.

The Project will cross areas identified as Limited Residential (LR) and Stream Protection (SP) on the Town of Whitefield Shoreland Zoning Map. Accordingly, CMP submits the attached application for review and approval by the Planning Board under the State of Maine Guidelines for Municipal Shoreland Zoning Ordinances (Aug. 7, 1994) (the "SZO"), which applies in Whitefield pursuant to Maine Department of Environmental Protection ("MDEP") rules chapter 1244.

The Project crosses areas along several streams designated as a Federal Emergency Management Agency (FEMA) Flood Zone. CMP therefore submits the attached application for approval from the Planning Board under the Floodplain Management Ordinance for the Town of Whitefield, Maine (Jan. 23, 2015) ("FMO").

The Project is related to, but separate from, the New England Clean Energy Connect ("NECEC"). The Project is required for interconnection of the NECEC to the existing New England Transmission System in accordance with requirements of the Tariff of ISO-New England Inc. ("ISO-NE") but also includes transmission line rebuilds and upgrades that are separate from the NECEC. CMP has applied for and obtained all necessary approvals from federal and state authorities to construct the NECEC. These permit approvals include the Section 3027 Project to be constructed in Whitefield as a transmission interconnection facility for the NECEC. The United States Army Corps of Engineers ("USACE") issued its permit on November 6, 2020. The Maine Department of Environmental Protection ("MDEP") issued its permits on May 11, 2020. The Maine Public Utilities Commission ("MPUC") issued a Certificate of Public Convenience and Necessity ("CPCN") on May 3, 2019.

2.0 PROJECT OVERVIEW AND DESCRIPTION

2.1 Project Overview

CMP proposes to construct the following transmission facilities, portions of which will be located in Whitefield:

New 345kV Transmission Line and Associated Rebuilds

- New 26.5-mile 345kV AC transmission line (Section 3027) from the existing Coopers Mills Substation in Windsor to the existing Maine Yankee Substation in Wiscasset;
- Partial rebuild of 0.3 mile of existing 345kV Section 3025 transmission line between Larrabee Road Substation in Lewiston and Coopers Mills Substation in Windsor;
- Partial rebuild of 0.3 miles of 345 kV Section 392 AC transmission line between the Coopers Mills substation and the Maine Yankee substation and approximately 3.5 miles of reconductor work on existing double circuit lattice steel towers outside of the Maine Yankee substation.

2.2 Project Description in Whitefield

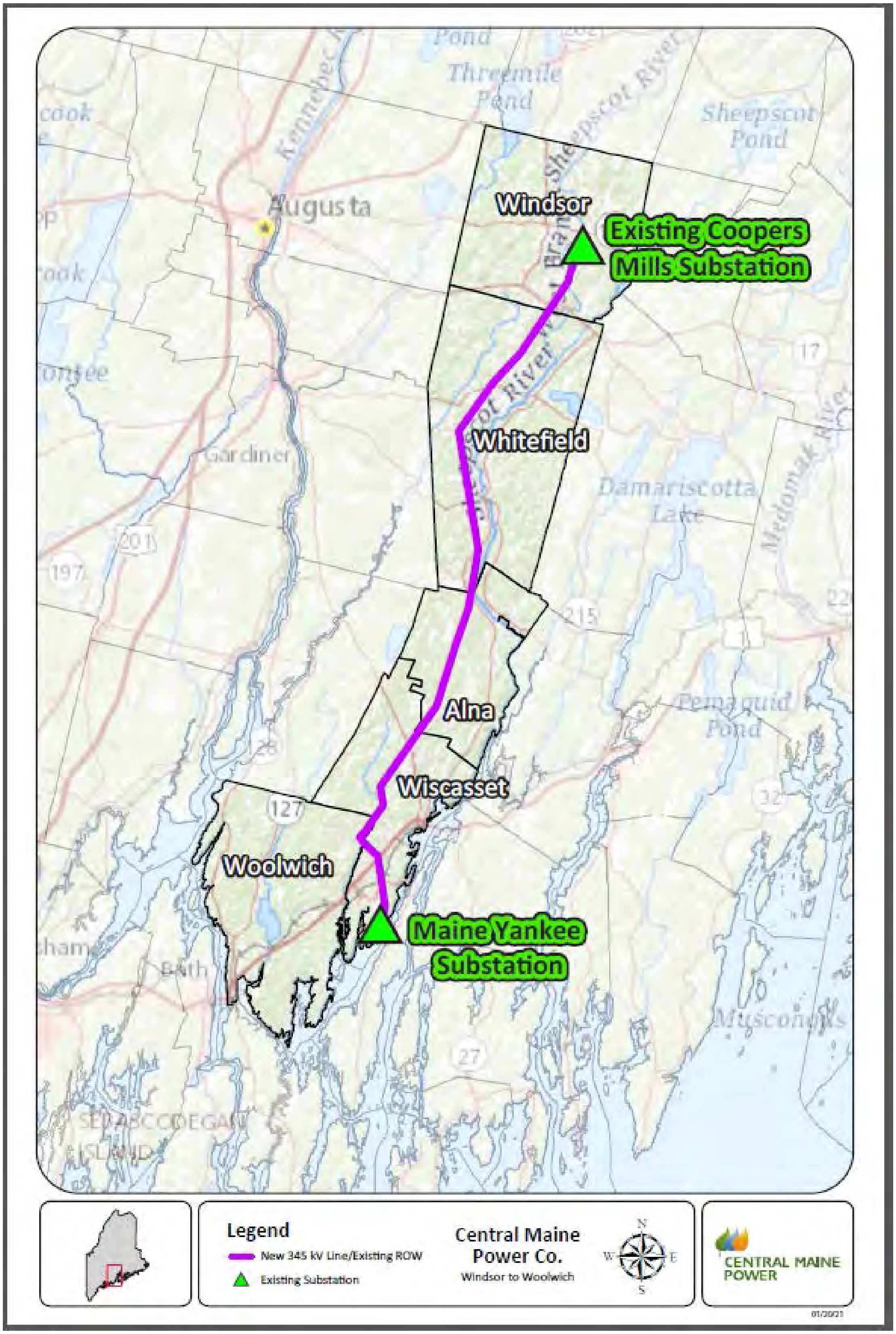
The Project is a 26-5-mile 345 kV transmission line that extends from Coopers Mills Substation in Windsor to the Maine Yankee Substation in Wiscasset (Figure 2-1). Withing Whitefield 10.9 miles of the proposed line will be located west of the Sheepscot River in an existing corridor that extends southward from the town boundary with Windsor, through Whitefield, and into Alna (Figure 2-2). Section 3027 will be co-located between the existing Section 392 345kV transmission line on the west and the Section 68 115 kV transmission line on the east. No additional vegetation removal is necessary for the Project in Whitefield. The Project will be built entirely on land that CMP owns in fee. See Exhibit 3 for proof of title, right, or interest and Exhibit 4 for a list of abutters.

The existing transmission line corridor in Whitefield traverses primarily undeveloped land and forested area. As explained in Table 1 below, a total of 95 poles will be installed in Whitefield. 91 pole locations involve installation of a combination of wooden H-frame poles that will be "direct embedded" into the ground (*i.e.*, with no foundations), two locations involve installation of self-supporting steel monopoles on drilled pier foundations, and two locations involve installation of three steel poles that will be placed on drilled pier foundations. The average height of the new poles is 86 feet. Each pole installation involves approximately 120 square feet of permanent disturbance. Natural resource maps are provided in Exhibit 1, and transmission line configuration cross sections (existing and proposed) are provided in Exhibit 2.

2.3 Environmental Considerations

Temporary in-corridor access roads will be used for pole installation. Timber mats will be used to cross wetlands and to fully span streams in order to protect natural resources. No in-stream work is proposed. Access roads and temporary pole preparation areas will be restored to pre-construction conditions and revegetated during project restoration.

Figure 2-1: Project Overview Map



Kennebec County
Lincoln County
Mills Rd
Augusta Rockland Rd
E River Rd
Whitefield
Pittston Rd
Head Tide Rd
S Clary Rd
Bunker Hill Rd
Legend
New 345 kV Line/Existing ROW
Township Boundary
Existing Substation
County Boundary
Central Maine Power Co.
Whitefield
N
S
E
W
CENTRAL MAINE POWER
04/09/21

Figure 2-2: Town of Whitefield Zoning Map

Proposed project location identified by orange dashed line

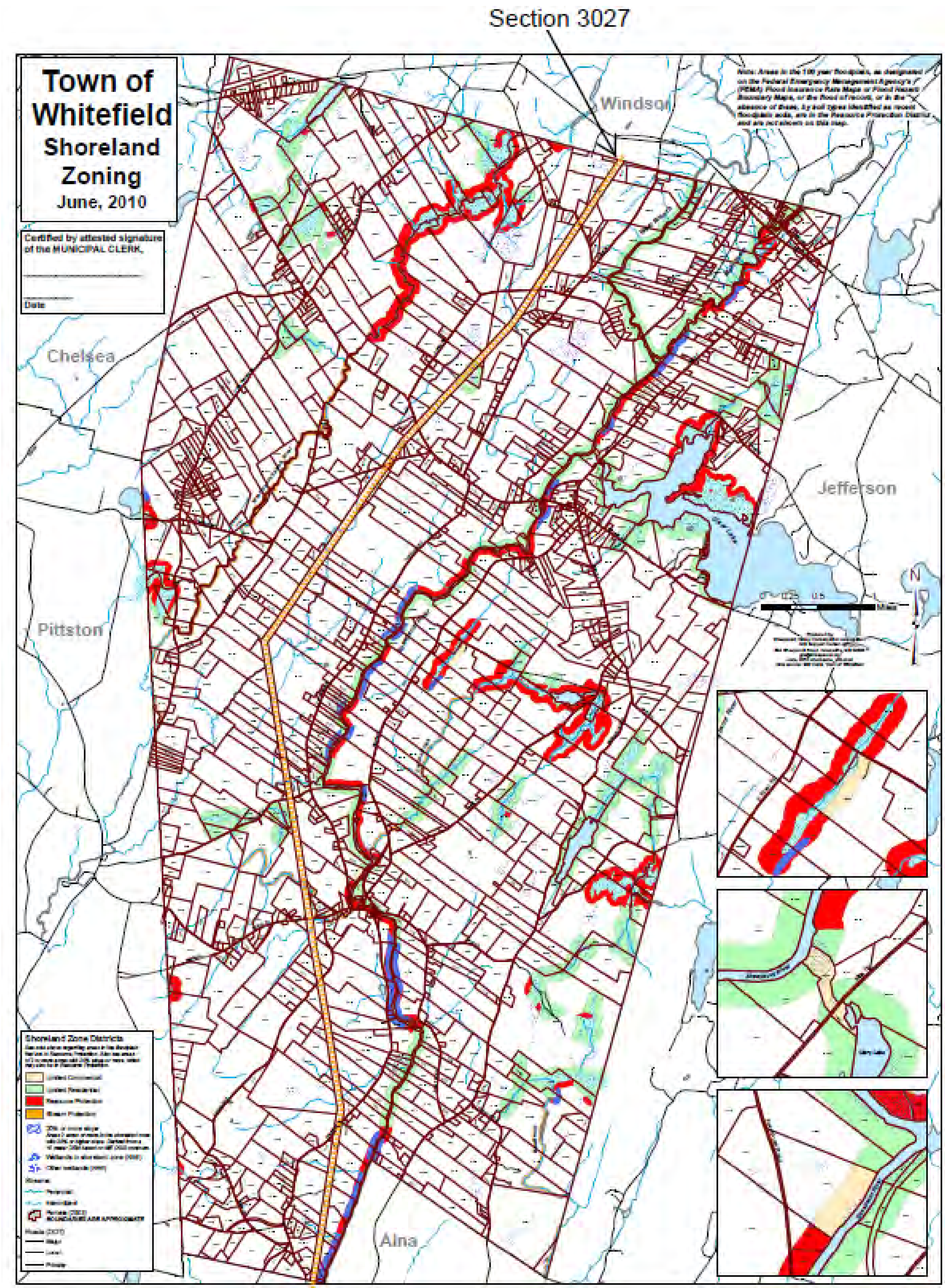


Table 1: Town of Whitefield– Existing and Proposed Transmission Line Sections

Transmission Line	Distance over which Changes Occur (miles)	Existing Poles (#)	Poles to be Removed (#)	New Poles (#)	New Pole Type & Height (Exhibit 2)	New Poles in Shoreland Zone (Exhibit 1)	New Poles in Floodplain
Proposed New Section 3027	10.9	N/A	N/A	95	91 – Wooden 2-Pole H-frames – 86' Average Height Two Steel Monopoles on Foundations - 110' Average Height Two 3-Poles on Foundations – 93' Average Height	12 3027-43, 44, 45, 46, 47, 48 (See Pages 6, 7 of 29) 3027-86, 87, 88, 89, 90, 91 (See Pages 18, 19, 20 of 29)	NONE
Existing Section 392	NO CHANGES						
Existing Section 68	NO CHANGES						
Totals	**-------**	**-------**	**-------**	**95**	**------**	**12**	**NONE**

CMP has developed procedures to avoid and minimize adverse environmental impacts during construction, operation, and maintenance of transmission lines. These procedures, which CMP uses as part of all transmission line and substation projects, were developed in consultation with the MDEP. These procedures are referenced throughout this application and demonstrate that the Project meets the applicable Town of Whitefield approval standards. A brief description of these plans and procedures follows:

- *NECEC Plan for Protection of Sensitive Natural Resources During Initial Vegetation Clearing* ("Vegetation Clearing Plan" or "VCP") (Exhibit 5)

- *NECEC Post Construction Vegetation Maintenance Plan* ("Vegetation Maintenance Plan" or "VMP") (Exhibit 6)

These two plans (collectively CMP's "Vegetation Management Plans") include strict performance standards applicable to the use of mechanized equipment and initial vegetation control practices to prepare the corridor for construction activities and for long-term maintenance of the transmission corridor in an early successional (scrub/shrub) habitat condition.

- *Environmental Guidelines for Construction and Maintenance Activities on Transmission Line and Substation Projects* ("Environmental Guidelines" Exhibit 7).

These Environmental Guidelines were developed in consultation with the MDEP and are based on MDEP's Maine Erosion and Sediment Control Best Management Practices ("BMPs") and MDEP's Chapter 500 rules and contain specific BMPs appropriate for electric transmission line and substation construction.

- *CMP's Environmental Control Requirements for CMP Contractors and Subcontractors - Oil and Hazardous Material and Waste* ("Environmental Control Requirements") (Exhibit 8).

These Environmental Control Requirements establish a set of minimum requirements for spill prevention and response. The procedures have proven effective for preventing spills and providing rapid spill response if spills occur.

CMP is committed to outreach and communications regarding fire and medical support during the construction and operation of the new transmission line. CMP's efforts in this regard will include discussions with local fire and emergency response personnel regarding records of any past fire and safety events in the corridor, an assessment of locally-available resources, and any additional fire safety provisions that have been included in construction contractors' scopes of work, which will be provided to local emergency response officials.

3.0 DEVELOPMENT PERMIT APPLICATION

The following application describes the Project's compliance with the Development Ordinance, including the application requirements in Section 7 and the standards in Section 8.

Section 7 – Procedures for Development Review

A. Pre-Application Meeting:

CMP appeared remotely before the Planning Board using ZOOM at its meeting on May 20, 2020, for the pre-application meeting required by Section 7 of the Development Ordinance. During this meeting, preliminary, "sketch plan-level" information was provided to the Planning Board, including Project maps and cross sections similar to Exhibits 1 and 2.

B. Development Application:

Identified by the Development Ordinance are items and information to be included with a development application that address map [7.B.1 (a-k)] and written content [7.B.2 (a-j]. Project maps appear as Exhibit 1 and Exhibit 1A and fundamentally present required information relevant to the project including north arrow, graphic scale, property boundaries, drainage ways, public and private rights of way, structures, and existing soils conditions. Certain specification such as- scale of not less than 1 inch to 100 feet and a perimeter survey by a registered land surveyor are requested to be waived by the Planning Board based on provided mapping satisfactorily depicts the physical characteristics of the proposed development.

Some map content however has not been provided either due to project construction being located along the center of the existing, cleared CMP-owned corridor or is otherwise simply by not applicable such as elevations of buildings, location of sanitary waste facilities or parking areas and topographic contours which will remain unchanged. Additionally, other identified map information is provided as written content elsewhere in the application such as names of abutting landowners and tax map and lot numbers (Exhibit 3, Exhibit 4). Similarly, specified written content relevant to the project appears on the application form or also as other supporting exhibits and addresses schedule, erosion and sedimentation control plan (Exhibit 7), and financial capacity (Exhibit 10)

Section 8 – Standards

A. Preservation and Enhancement of the Landscape

The Project preserves the natural landscape.[1] The Project will be co-located within an existing 300-foot wide transmission line corridor established more than two decades ago. Soil disturbance over the 10.6 mile length will be limited to the area around the 95 pole locations and temporary construction access roads, which will be restored to pre-development conditions once construction is complete. No vegetation removal will be necessary because the Project will be co-located within the existing maintained corridor. The forested buffer that currently exists along the corridor will not be disrupted, making unnecessary additional landscaping or screening for the new transmission line in the center of the existing right of way. Therefore, the Project will retain existing vegetation and will not encroach on neighboring land uses.

B. Relation of Proposed Development to the Environment

Constructing the Project within the existing corridor minimizes impacts on the surrounding uses and resources, including impacts to natural resources. Within the corridor, CMP has sited each pole to avoid or minimize impacts on surrounding uses, protected natural resources and natural features such as slope, soil types and drainage ways, and to the scenic or natural beauty of the area, historic sites, and rare and irreplaceable natural areas. Based on pre-construction fieldwork, including wetland delineations, vernal pool and plant surveys, and evaluation of wildlife habitat along the established transmission line corridor, the Project will not disturb, displace, destroy or impair rare or endangered plants, animals or animal habitat in Whitefield. Accordingly, the Project will not impair, disturb, or displace any rare or endangered form of animal or plant life in Whitefield.

C. Air Quality

The Section 3027 transmission line Project will not create levels of dust, dirt, fly ash, vapors or gas emissions that could lower ambient air quality beyond the existing transmission line corridor. Minimal, localized and temporary influences on air quality from construction activities, such as exhaust from diesel engines, may occur during

[1] While the Project will not have an undue adverse effect on the natural landscape, CMP objects for the record to this standard. The Maine Supreme Court has held that similar ordinance provisions applying a subjective visual impact approval are void for vagueness. *See, e.g., Kosalka v. Town of Georgetown*, 752 A.2d 183, 186-87 (Me. 2000) (finding an ordinance provision that requires a development to “conserve natural beauty” void for vagueness); *Cope v. Inhabitants of Brunswick*, 464 A.2d 223, 227 (Me.1983) (finding requirements to protect the “health, safety and welfare of the public and the essential character of the area” are not sufficiently specific).

construction. Due to the limited duration of work at the location and the general rural nature of the Project area, any effects on overall air quality will be insignificant and will not extend beyond the corridor.

Fugitive dust is only anticipated along unpaved, in-corridor temporary construction access roads. CMP will employ BMPs to minimize fugitive dust emissions including:

1. Use of water or other wetting agents on areas of exposed or dry soils.
2. Use of load covers for transport of soils or other dry granular material.
3. Controlled onsite storage of spoils with mulch, hay, tarps, erosion control mix or silt fencing; and
4. Final grading, landscaping, and revegetation or permanent stabilization with approved materials as soon as practical.

D. Water Quality and Quantity

The Section 3027 transmission line Project will not require an on-site water supply well or septic system that could affect the quality or quantity of groundwater on abutting properties. During construction, potential sources of groundwater contamination will be limited to fuel and hydraulic and lubrication oils used in the operation and maintenance of vehicles and construction equipment. Spill reporting and cleanup procedures will be in place to promptly contain and clean up any spills, as described in the Environmental Control Requirements (Exhibit 8), which establish a set of minimum requirements for spill prevention and response for CMP contractors and subcontractors. These requirements have proven effective for preventing spills, addressing spills if they occur, and preventing groundwater degradation during construction, operation, and maintenance of other CMP projects. During Project maintenance and operation, potential sources of groundwater contamination will include fuel and hydraulic and lubrication oils used in the operation and maintenance of vehicles.

The Project will not result in undue surface water pollution or significantly change the quantity or quality of stormwater runoff. Due to the very small amount of new impervious surface, current surface water drainage patterns across the site will be largely unaffected by the Project, and the Project will not significantly change stormwater volumes in the area. In addition, CMP will not conduct significant grading or grubbing and will maintain the corridor in a vegetated state. Surface water runoff as a result of the Project will not adversely affect neighboring properties, downstream water quality, or the public storm drainage system. In addition, CMP will apply measures to control erosion and sedimentation both during and after construction, as described below and set forth in Exhibit 7.

E. Noise Levels

The Project will not generate noise levels to the extent that abutting or nearby property owners will be inconvenienced or harmed in any way. For electric transmission lines, audible sound is relative to conductor (wire) size. CMP has selected a conductor size that under dry conditions is designed to be nearly sound free; under adverse weather conditions (*e.g.*, very high humidity and storm conditions) these conductors may emit a slight crackling sound. Sound is produced when protrusions on the conductor surface –

particularly water droplets on the conductors or dripping off the conductors – cause the electric field intensity at the conductor surface to exceed the breakdown strength of air, producing sound. The sound increases from transmission lines results from the partial electrical breakdown of air around the conductors. In small volumes near the surface of the conductors, energy and heat are dissipated. Part of this energy is in the form of small local pressure changes that result in sound that can be characterized as a hissing, crackling sound. Sound from transmission lines is typically a foul-weather/wet conductor phenomenon.

Based on the BPA model results for the Project, all sound levels produced by the transmission lines associated with the Project are expected to remain within MDEP's sound level limits. It was calculated that the transmission line conductor sound levels at the edges of the ROW, in fair weather conditions, will be well below the applicable noise standards, with the maximum typical levels at the edge of ROW expected to be approximately 28 dBA. This level is generally negligible, and the sound will dissipate quickly as distance from the edges of the ROW increases.

Construction of the Project will take place during normal working hours and will not raise noise levels to inconvenience or harm abutting or nearby property owners. The construction contractor selected will implement, where appropriate, construction methods that maintain construction noise below the MDEP's sound level limits.

F. Vehicular Access

Prior to construction activities, CMP will establish temporary, in-corridor access points from public or private roadways. An adequate number of access points will be established in locations that provide safe access with respect to sight distances and intersections, schools or other applicable traffic generators. All access points will be used exclusively for construction and maintenance activities and will be restored immediately after completion of construction. CMP's Environmental Guidelines (Exhibit 7) establish measures that will be used to prevent erosion and sedimentation from entering the public ROW and encourage proper drainage or runoff, and CMP will use safety signage at all such access points. Construction equipment will be temporarily parked in the corridor, outside of protected natural resources and their buffers. Some material and equipment deliveries may require vehicles to stop or back into a street. During these infrequent occasions, spotters or flaggers will be used to assist vehicles moving into or out of the corridor or around a stopped vehicle.

During operation of the transmission line, access points similar to those used for maintenance and repair of the existing transmission lines will continue to be used for routine and emergency transmission line maintenance and repair. Occasional use of these in-corridor access points will not cause unreasonable highway or public road congestion.

G. Surface Water Drainage

The Project will minimize stormwater runoff by deploying stormwater control methods described in the Environmental Guidelines (Exhibit 7). Existing natural runoff control features such as upland vegetated buffers, and diversion and dissipation techniques such as water bars, check dams or settling basins will be utilized for temporary access roads and construction activities. After construction is complete, all disturbed areas will be returned to preconstruction contours, reseeded as needed, and allowed to revegetate to scrub-shrub conditions. The Project will meet the requirements of the Stormwater Management Law (38 M.R.S. § 420-D) for utility corridors.

H. (Subsection intentionally left blank by Ordinance)
Not applicable.

I. Utilities
Not applicable. The Project involves installation of a new transmission line and will not alter or burden existing public utilities.

J. Advertising Features
Not applicable. The Project does not involve any exterior signs or advertising.

K. Special Features
Not Applicable. The proposed transmission line is sited within an existing CMP transmission line corridor, minimizing the impacts on the surrounding land uses and properties. The Project will not adversely impact other land uses within the development area, which consists of electrical transmission ROW, open land and forested land; therefore, no additional setbacks or screening are necessary or proposed.

L. Exterior Lighting
Not applicable. The Project does not involve exterior lighting.

M. Emergency Vehicle Access
Prior to construction activities, CMP will establish temporary access points from public roadways if no access currently exists. Temporary access ways will also be established within the corridor to access the work areas. These temporary access points will be suitable for use by emergency response vehicles.

During operation of the transmission line, access points similar to those used to service the existing transmission line will be used for routine and emergency transmission line maintenance. Fire and police will be able to access the corridor using these same access points in the event of an emergency.

Based on an initial meeting with the first chief, CMP understands that Whitefield is a part of a Mutual Aid Group that also includes Windsor, Somerville Jefferson, and other towns as needed, and that EMT services are provided by Delta Ambulance.

N. Mineral Extraction/Gravel Mining
Not applicable.

O. Rock Crushing, Asphalt Batch Plants and Quarrying
Not applicable.

4.0 SHORELAND ZONING PERMIT APPLICATION

The following application describes the Project's compliance with the SZO.

Shoreland Zoning Districts in the Project Area

According to the Town of Whitefield Shoreland Zoning Map (Figure 2-2), Section 3027 will cross two Limited Residential (LR) districts and one Stream Protection (SP) district and require installation of the 12 poles listed in Table 1. These districts are identified and described as follows:

1. LR District associated with a wetland located north of Cooper Road and south and east of Devine Road is crossed by the existing transmission line corridor (Exhibit 1: pages 6, 7).

2. LR District associated with a wetland located north of Philbrook Road on the west side of the existing transmission line corridor (Exhibit 1: pages 18, 19, 20).

3. SP District located north of Pittston Road (Route 194) along Chamberlain Brook is crossed by the existing transmission line corridor (Exhibit 1: page 20).

Permitted Land Uses

According to Table 1 in Section 14 of the Shoreland Zoning Ordinance, Essential Services, such as Section 3027, are a permitted land use in the LR and SP Districts with approval of the Planning Board. However, further restrictions apply in these districts as detailed in Section 15 - Land Use Standards, specifically Section 15(L), which provides:

> 1. *Where feasible, the installation of essential services shall be limited to existing public ways and existing service corridors.*
>
> 2. *The installation of essential services is not permitted in a Resource Protection or Stream Protection District except to provide services to a permitted use within said district, or where the applicant demonstrates that no reasonable alternative exists. Where permitted, such structures and facilities shall be located so as to minimize any adverse impacts on surrounding uses and resources including visual impacts.*

Due to the linear nature of the Project and the need to minimize impacts by co-locating the new transmission line adjacent to existing transmission lines within an existing right of way, the LR and SP Districts could not be completely avoided. Further discussion is provided below.

Section 15 - Land Use Standards

The following section addresses the Land Use Standards found in Section 15 of the SZO.

A. Minimum Lot Standards

Not applicable. The project does not meet the use types requiring minimum lot standards as per Section 15(A)(1) and will not have principal structures (as defined) located on the lot, as discussed below.

B. Principal and Accessory Structures

Not applicable. "Principle structure" is defined in Section 17 of the SZO as "a building other than one which is used for purposes wholly incidental or accessory to the use of another building or use on the same premises." "Accessory structure" is defined as a "structure which is incidental and subordinate to the principal use or structure." The transmission line poles are not a "building" because the poles do not include walls and a roof. The transmission line poles accordingly do not meet the definition of a *Principal Structure*, nor do they meet the definition of an *Accessory Structure*, as those terms are defined in Section 17 of the SZO.

The transmission line poles are also not "structures," as that term is defined in the SZO. The definition of "structure" in Section 17 of the SZO excludes "poles, wiring and other aerial equipment normally associated with service drops as well as guying and guy anchors." MDEP has stated that transmission lines and associated poles fall within this exclusion from the definition of "structures" because "poles and wiring" includes "electric power lines, whether the wires are for distribution or transmission of electricity, and the poles that support these wires, along with telephone poles and lines and similar cable and internet infrastructure." MDEP stated that, together with the language "other aerial equipment normally associated with service drops," these exemptions facilitate the delivery of essential services to end users, in the case of electric power, by capturing transmission and distribution lines, as well as service drops." *See* June 8, 2020 Letter from Colin Clark, MDEP, to Tom Marcotte, Code Enforcement Officer, Town of Industry (Exhibit 9).

C. Pier, Docks, Wharves, Bridges, etc.

Not applicable. The Project will not require access from the shore and will not interfere with beach areas. No new or existing structures will be built on, over or abutting a pier, dock, wharf, or other structure extending beyond the normal high water line of a water body or within a wetland. There will be no in-stream work and CMP will comply with the applicable riparian buffers described in its Vegetation Management Plans (VCP and VMP), and implement its environmental protection requirements described in its Environmental Guidelines and Environmental Control Requirements, such that impacts will be minimized and there will be no adverse impacts to fisheries.

D. Campgrounds

Not applicable.

E. Individual Private Campsites

Not applicable.

F. Commercial and Industrial Uses

Not applicable. The Project is a classified as an Essential Service under the SZO.

G. Parking Areas
Not applicable. There will be no permanent parking areas associated with the Project within the shoreland zone.

H. Roads and Driveways
There will be no permanent roads or driveways associated with the Project in Whitefield.

Temporary access ways will be established for equipment access within the corridor for construction and maintenance purposes. These temporary access ways will be in place for less than 18 months.

CMP's Environmental Guidelines contain requirements and best practices regarding temporary access road installation. Consistent with these guidelines, measures will be taken to avoid and minimize impacts to streams and wetlands using timber mats, temporary bridges, geo-textile fabrics, and culverts, when necessary.

If necessary, timber mats will be placed parallel to the upland edge of streams as abutments to further protect bank stability. No grubbing (removal of root systems) within the shoreland zones will be done prior to mat placement. However, some minor grading may be required to ensure mat stability and construction access safety. Any such grading will be limited and only with prior approval by CMP's environmental representatives.

Appropriate erosion controls will be installed as per the Environmental Guidelines. After construction has been completed, disturbed areas associated with temporary access ways will be returned to preconstruction contours, reseeded as needed, and stabilized. The transmission corridor will be permanently maintained in a scrub-shrub condition.

I. Signs
Not applicable. There are no signs proposed as part of the Project in Whitefield.

J. Storm Water Runoff
The Project will minimize stormwater runoff by deploying stormwater control methods described in the Environmental Guidelines. Temporary access roads and construction activities will be carefully planned and designed to utilize existing natural runoff control features, such as upland vegetated buffers, and diversion and dissipation techniques such as water bars, check dams, or settling basins. Shrubby vegetation will be retained to the extent practicable and the extent and duration of soil exposure during construction will be minimized. After construction is complete, all areas will be returned to preconstruction contours, reseeded as needed, and allowed to revegetate to a scrub-shrub condition. The Project will not alter stormwater runoff from predevelopment conditions.

K. Septic Waste Disposal
Not applicable. There is no septic waste disposal associated with the Project.

L. Essential Services
(1) Where feasible, the installation of essential services shall be limited to existing public ways and existing service corridors.

In Whitefield construction of Section 3027 will occur entirely within CMP's existing 300-foot wide transmission line corridor between existing transmission line Section 392 on the west and existing transmission line Section 68 on the east. The Project will be built entirely on land that CMP owns.

(2) The installation of essential services other than road-side distribution lines, is not allowed in a Resource Protection or Stream Protection District, except to provide services to a permitted use within said district, or except where the applicant demonstrates that no reasonable alternative exists. Where allowed, such structures and facilities shall be located so as to minimize any adverse impacts on surrounding uses and resources, including visual impacts.

Section 3027 in Whitefield does not cross an RP District. The existing transmission line corridor crosses the SP district at one location at Chamberlain Brook, but no poles will be located in the SP district. Therefore, the Project does not involve "installation" of any essential services in the SP District because Section 3027 will pass overhead.

Nevertheless, the Project satisfies this standard. No reasonable alternative to crossing this SP district exists, and CMP has minimized the impact of the new transmission line by co-locating it within an existing transmission line corridor. Doing so minimizes impacts on the surrounding uses and resources, including natural resources and visual impacts. The alternative to CMP's proposal would be to acquire additional land rights and site the transmission line in an entirely new corridor, which would not be a reasonable alternative because it would have greater impacts, and CMP would likely be unable to avoid the district that runs with the resource in any case. Within the corridor, CMP has sited each pole to avoid impacts on surrounding uses and protected natural resources to the greatest extent practicable, and to minimize and compensate for impacts that cannot be avoided.

Given the Maine state requirement to avoid and minimize environmental and visual impacts, avoidance of the SP district was not possible, and there are therefore no reasonable alternatives to an aerial crossing of the SP district associated with Chamberlain Brook. Avoiding this district would require complete relocation of the transmission line corridor. The overall environmental and visual impacts of this alternative would exceed the impacts associated with the Project as planned.

M. Mineral Exploration and Extraction

Not applicable.

N. Agriculture

Not applicable.

O. Timber Harvesting

Not applicable.

P. Clearing or Removal of Vegetation for Activities Other Than Timber Harvesting

Some vegetation removal will be required within the existing transmission line corridor to accommodate pole installation and ensure that the Project meets federal reliability and safety standards. The vegetation removal standards of Section 15(P) do not apply to vegetation removal that is necessary for uses expressly authorized in the district (such as essential services).

The amount of vegetation removal in the LR and SP Districts will be limited such as for removal of a safety hazard and will be conducted in accordance with the Vegetation Management Plans. Where the SP District overlaps with the 100-foot protected riparian buffers, CMP has established additional protections as part of the Vegetation Management Plans, which are summarized as follows:

Tree clearing in the riparian buffers will be performed during frozen ground conditions whenever practicable and, if not practicable, the recommendations of the environmental inspector will be followed regarding the appropriate techniques to minimize disturbance, such as the use of selectively placed travel lanes within the stream buffer. Within that portion of the stream buffer that is within the wire zone (i.e., within 15 feet, horizontally, of any conductor) all woody vegetation over 10 feet in height, whether capable or non-capable, will be cut to ground level. No other vegetation, other than dead or hazard trees, will be removed. Removal of capable species, dead, or hazard trees within the stream buffer will typically be accomplished by hand-cutting. Use of mechanized harvesting equipment is allowed if supported by construction matting or during frozen conditions in a manner (i.e., use of travel lanes and reach-in techniques) that preserves non-capable vegetation. Root systems are left intact unless a structure is to be placed where one or more trees are currently located; as a result, grubbing is limited. All slash (such as branches, tops and uprooted stumps) from the cutting operation will be managed in accordance with the Maine Slash Law. The vegetation that remains is typically a scattered growth of small shrubs and herbaceous plants. Initially, the condition of these newly cleared areas resembles that of a high quality forestry operation. Over a relatively short period of time (generally within one year) the newly cleared portions of the corridor will exhibit the early-successional scrub shrub habitat type that is typical of existing transmission line corridors in Maine.

After construction is completed, follow-up maintenance activities during operation of the line require the removal of “capable species,” dead trees and “hazard trees.” Capable trees are those woody plant species and individual specimens that are capable of growing tall enough to violate the required clearance between conductors and vegetation established by the North American Electric Reliability Corporation (“NERC”). More frequent vegetation management may be required within the first 3 to 4 years following construction to bring the vegetation under control, but after this initial management period, maintenance practices are typically carried out on a 4-year cycle depending on growth, weather, geographic location, and corridor width. Non-capable species are allowed to grow to ensure that the corridor is vegetated to the greatest extent allowable, which helps prevent erosion and provides wildlife habitat. Maintenance procedures will include cutting all capable species and any dead or hazard trees at ground level, primarily using hand tools, with the occasional use of chain saws and limited use of motorized equipment in areas directly accessible from public or private access roads. Large vegetation cut during routine maintenance will be managed in accordance with the Maine Slash Law. Selective herbicide application will be used in conjunction with mechanical methods of vegetation control; however, herbicides will not be used within the riparian buffers associated with the SP and RP districts.

Please refer to the Vegetation Management Plans (Exhibit 6) for additional procedures and restrictions related to the Shoreland Zone.

Q. Erosion and Sedimentation Control

CMP's Environmental Guidelines (Exhibit 7), which are used as a routine part of all transmission and substation projects, contain erosion and sedimentation control requirements, standards, and methods that will be used to protect soil and water resources during construction of the various Project components. The manual was developed in consultation with the MDEP and is based on MDEP's Maine Erosion and Sediment Control Best Management Practices ("BMPs") and MDEP's Chapter 500 rules and contains specific BMPs appropriate for electric transmission line construction. These guidelines will be followed in the construction of the transmission line in Whitefield and are consistent with the requirements of this ordinance.

The Project will not result in undue soil erosion or sedimentation or adversely affect neighboring properties, downstream conditions, or public storm drainage. The Project has been designed to fit the existing topography and soils of the site and will utilize natural contours as closely as possible to minimize soil exposure and the potential for erosion. Project activities will be sequenced to minimize exposed soils and will provide temporary stabilization during construction and permanent stabilization after construction is completed, consistent with the requirements of the SZO.

There will be no permanent conversion of vegetated areas to impervious surface other than the limited area around and including the transmission line poles themselves. Tree clearing will be conducted as per the VCP, which includes strict performance standards to minimize soil disturbance, erosion, and sedimentation. After construction is complete, all disturbed areas will be temporarily stabilized until permanent vegetative cover is achieved. The corridor will be maintained as early successional scrub-shrub habitat. Vegetation will be maintained on a four-year cycle to ensure vegetation does not reach heights that threaten safety or the reliability of the transmission lines. Vegetation maintenance procedures are described in the VMP. Generally, heavy equipment will not be necessary for vegetation control after the initial clearing of the corridor; vegetation will be maintained by hand-cutting and/or limited herbicide use, thereby minimizing the potential for soil disturbance.

R. Soils

Based on the Soil Survey Geographic Database compiled by the United States Department of Agriculture – Natural Resources Conservation Service, the Project will be located on soils in or upon which the proposed uses and structures can be established and maintained without causing adverse environmental impacts, including severe erosion, mass soil movement, improper drainage, and water pollution, during and after construction. Soil constraints within the transmission line corridor will be managed and mitigated through implementation of erosion and sedimentation control measures, proper siting and project design, and proper construction sequencing. A soils report for the transmission line components located in Whitefield is not required since the Project does not require subsurface waste disposal and is not considered a commercial or industrial development, as those terms are defined in the SZO, or other similar intensive land uses.

S. Water Quality

The Project will not deposit on or into the ground or discharge to the waters of the State any pollutant that, by itself or in combination with other activities or substances, will impair designated uses or the water classification of the water body, tributary stream or wetland. To protect water quality and minimize spill potential during construction, no fueling or maintenance of vehicles will be performed within 100 feet of wetlands, streams, or other sensitive natural resources, unless done on a paved road. As described in the VMP (Exhibit 6), CMP uses a selective herbicide program to treat areas once every four years to maintain early successional scrub shrub growth. Herbicide is selectively applied (using a low-pressure backpack-mounted applicator) to individual capable specimens to prevent growth of individual plants (or re-growth of a cut plant). Herbicides will not be used within the 100-foot riparian buffers associated with the SP districts.

The multiple methods, plans, and procedures to prevent water quality degradation during construction, operation, and maintenance of the NECEC are incorporated into CMP’s Environmental Control Requirements, Vegetation Management Plans, and Environmental Guidelines.

T. Archaeological Sites

CMP has conducted extensive pre-historic archaeological, historic archaeological, and historic architectural investigations and surveys along the Project route, for State purposes under Chapter 375.11 of the MDEP rules and for federal action under Section 106 of the National Historic Preservation Act (16 U.S.C § 470-f). CMP has consulted with the Maine Historic Preservation Commission throughout the state and federal permit application development and approval process. No archaeological sites or historical properties listed on, or eligible to be listed on, the National Register of Historic Places were documented within the Shoreland Zone in Whitefield.

Approval Standards

The following section addresses the Approval Standards found in Section 16(D) of the SZO.

1. Maintain safe and healthful conditions.

Meets the criteria. The Project will maintain the same safe and healthful conditions that currently exist in the transmission line corridor. The infrastructure and equipment in the transmission line corridor is regularly maintained to established industry standards to ensure the safety of utility workers and the general public.

Maintaining sufficient clearances around the conductors is paramount to the safe and reliable operation of the transmission lines. These clearances are achieved through appropriate siting of the poles themselves and through the vegetation maintenance practices described above. All construction will be in accordance with CMP's transmission standards and general industry standards, including all necessary live-line working clearances, strength factors, and reliability factors as governed by the National

Electrical Safety Code ("NESC"). In all instances, the line will be designed to meet or exceed the NESC and other applicable standards. The transmission line and all facilities will be operated in full compliance with CMP safety standards, which fully comply with Federal Occupational Safety & Health Administration requirements.

2. **Not result in water pollution, erosion, or sedimentation to surface waters**
Meets the criteria. As described above with respect to SZO Sections 15(J), (P), (Q) and (S), the Project will not result in water pollution, erosion, or sedimentation to surface waters.

3. **Adequately provide for the disposal of all wastewater**
Meets the criteria. There will be no wastewater disposal required for this Project.

4. **Not have an adverse impact on spawning grounds, fish, aquatic life, bird or other wildlife habitat**
Meets the criteria. In order to identify existing resources, field biologists documented wildlife while conducting extensive field surveys for the Project.

   In addition, CMP conducted fish and wildlife database searches and contacted state and federal natural resource agencies to obtain and evaluate existing data on wildlife and fisheries resources in the vicinity of the Project. There are no deer wintering areas, vernal pools, rare, threatened or endangered species, moderate or high value inland waterfowl and wading bird habitats, or significant wildlife habitat identified within the mapped shoreland zones crossed by the Project corridor in Whitefield. There will be no in-stream work, and CMP will require the applicable riparian buffers, described in its Vegetation Management Plans (VCP and VMP), and implement its environmental protection requirements described in its Environmental Guidelines and Environmental Control Requirements, such that impacts will be minimized and there will be no adverse impacts to fisheries and aquatic life.

5. **Conserve shore cover and visual, as well as actual, points of access to inland waters**
Meets the criteria. The Project will take place entirely within the existing corridor and does not include alterations to points of access to inland waters.

6. **Protect archaeological and historic resources as designated in the Comprehensive Plan**
Meets the criteria. As discussed above with respect to SZO Section 15(T), the Project will not impact any archaeological and historic resources.

7. **Avoid problems associated with flood plain development and use**
Meets the criteria. As discussed further in the Floodplain Management application, no portion of the Project occurs within a FEMA designated floodplain. Because of the nature of a transmission line and essentially no increase in impervious surface by the Project, construction and maintenance of the proposed transmission line will not cause or increase flooding or cause a flood hazard to any neighboring structures. Furthermore, the Project will not affect runoff/infiltration relationships.

8. **Be in conformance with the provisions of Section 15, Land Use Standards**

Meets the criteria. With respect to SZO Section 15 described above, the Project complies with all applicable provisions of the Ordinance.

5.0 FLOODPLAIN MANAGEMENT PERMIT APPLICATION

The following application section complies with the FMO. It identifies the regulated Federal Emergency Management Agency ("FEMA") delineated floodplains within the Project area and addresses the requirements of Articles III, VI, and VIII.

FEMA Flood Hazards Zone

The Project will cross seven FEMA-mapped 100-year Flood Zones in Whitefield. The flood zone area is shown on the FEMA Flood Insurance Rate Maps (FIRM) for the town of Whitefield (Community Panel Nos. 23015C 0110D, 0120D and 0130D effective date: July 16, 2015). The flood zones are identified as Zone A. The proposed Project activities within the 100-year flood zone are described as follows:

- Finn Brook - The existing CMP corridor crosses the flood hazard area associated with Finn Brook south of Devine Road. The proposed transmission line will span the flood zone, and no poles will be located within the flood zone.

- East Branch Eastern River – The existing CMP corridor crosses the flood hazard area associated with the East Branch Eastern River in four locations south of Gardiner Road and to the west of Townsend Road. The proposed transmission line will span the river, and no poles will be located within the flood zone.

- Chamberlain Brook – The existing CMP corridor crosses the flood hazard area associated with Chamberlain Brook north of the Pittston Road (Route 194). The proposed transmission line will span the flood zone, and no poles will be located within the flood zone.

- Sheepscot River Tributary 11.1.1 – The existing CMP corridor crosses the flood hazard area associated with Tributary 11.1.1 of the Sheepscot River south of the Pittston Road (Route 194). The proposed transmission line will span the flood zone, and no poles will be located within the flood zone.

In summary, CMP will install no poles within any of the seven FEMA-mapped flood hazard areas in Whitefield. Therefore, there will be no flood zone impacts from construction of Section 3027 in Whitefield.

Article III – Application for Permit

The following section includes the information requested in Article III of the FMO.

The name, address phone number of the applicant
<u>Applicant and Owner:</u>
Central Maine Power Company
83 Edison Drive
Augusta, Maine 04336
Attention: Gerry J. Mirabile 207-242-1682

A. Map indicating the location of the construction site
The map provided in Figure 2-2 show shows the extent of the 10.9-mile long Project in the Town of Whitefield.

B. A site plan showing location of existing and/or proposed development
Exhibit 1 includes aerial photo-based maps showing detailed Project information in Whitefield, including the location of the CMP corridor, existing and proposed pole locations, proposed access ways, flood zones, wetlands and waterbodies, and other natural resource data. There will be no sewage disposal facilities or water supply facilities associated with the Project. Additionally, there will be no cut and fill that would cause a permanent change in topography. The transmission line has been sited and designed to conform with existing topography, and any areas requiring grading or cut and fill for construction purposes will be returned to original contours and permanently stabilized with vegetation.

C. Statement of the intended use
The proposed development over the floodplain consists of the construction of a new Section 3027 345kV transmission line within an existing transmission line corridor.

D. Statement of the cost of the development, including all materials and labor
The portion of the project that is within the flood zone in the Town of Whitefield is anticipated to cost $1,400,000, including all materials and labor.

E. Statement as to the type of sewage system proposed
Not applicable. No sewage system is proposed as part of the Project in the Town of Whitefield.

F. Specification of dimensions of the proposed structure
In Whitefield, Section 3027 will consist of 91 2-pole wooden H-frames with an average height of 86’, two steel monopoles on foundations with an average height of 110’, and two steel 3-poles on foundations with an average height of 93’.

G. Base Flood Elevation
Not applicable. The standards at Items H through K.2 apply only to the new construction or substantial improvement of “structures.”. According to the FMO, “*Structure* means, for floodplain management purposes, a walled or roofed building.” Transmission line poles do not meet this definition, and no poles will be installed in the 100-year floodplain in any case. As such, the elevation reference points in Section H do not apply to the Project.

H. Elevation Reference Point
Not applicable.

I. Base Flood Elevation Certification
Not applicable.

J. Floodproofing Methods Certification
As per the Ordinance, K.1 and K.2 do not apply to the transmission line poles since they do not meet the definition of a structure. The Project also does not include any bridges or containment walls; therefore, K.3 and K.4 do not apply.

L. Water Course Alterations
The Project does not include any poles within the floodplains of Finn Brook, the East Branch of the Eastern River, Chamberlain Brook or Sheepscot River Tributary 11.1.1. These waterways will be spanned aerially. Section 3027 will therefore not alter or relocate the course of any waterway or associated floodplain.

M. Compliance with Section VI
The Project's compliance with the Section VI Development Standards is presented in the following section.

Article VI – Development Standards

A. All Development
The Project will consist of 85-foot tall wooden H-frame structures that will be either direct embedded into the ground or installed on concrete foundations, depending on soil or substrate conditions. The poles are designed to meet or exceed the National Electrical Safety Code (NESC 2017), Section 250 and 251. In addition to those strength and loading requirements, the effects of buoyancy and any lateral loadings resulting from hydraulic loadings are considered, where applicable, and addressed in Project design to prevent flotation, collapse or unacceptable lateral movement.

B. Water Supply
Not applicable. There will be no water supply systems.

C. Sanitary Sewage Systems
Not applicable. There are no proposed sanitary sewage systems.

D. On Site Waste Disposal Systems
Not applicable. There are no on-site waste disposal systems proposed.

E. Watercourse Carrying Capacity
Not applicable. There will be no alterations or relocations of watercourses.

F. Residential Structures
Not applicable. The Project is not a residential structure.

G. Non-Residential Structures
Not applicable. The Project is not a non-residential structure.

H. Manufactured Homes
Not applicable. The Project is not a manufactured home.

I. Recreational Vehicles
Not applicable. The Project is not a recreational vehicle.

J. Accessory Structures
Not applicable. The Project is not an accessory structure.

K. Floodways
Not applicable. No part of Section 3027 in Whitefield will be located in a FEMA designated floodway.

L. Enclosed Areas Below the Base Floor
Not applicable.

M. Bridges
Not applicable.

N. Containment Walls
Not applicable

O. Wharves, Piers and Docks
Not applicable

Article VIII – Review of Subdivision and Development Proposals

The following section includes the information required for review by the Planning Board in Article VIII of the FMO for development requiring review under other federal law, state law or local ordinances or regulations and projects on five acres or more.

A. All such proposals are consistent with the need to minimize flood damage.

CMP has minimized the impact of the new transmission line by co-locating it within an existing transmission line corridor. Co-locating the new transmission line within an existing transmission line corridor minimizes impacts on the surrounding uses and resources, including natural resources. Within the corridor, CMP has sited each pole to avoid impacts on surrounding uses and protected natural resources to the greatest extent practicable, to minimize these impacts, and to compensate for impacts that cannot be avoided. No poles will be within the 100-year floodway.

B. All public utilities and facilities, such as sewer, gas, electrical and water systems are located and constructed to minimize or eliminate flood damages.

No sewer, gas, or water systems are proposed by this Project. The Project involves the construction of a new 345kV electric transmission line and is appropriately located to minimize flood damages.

C. Adequate drainage is provided to reduce exposure to flood hazards.

Except for the immediate area occupied by poles, there will be no increase in impervious surface area associated with the transmission line; therefore, there will be no significant storm water run-off generated from the Project. The Project will not cause or increase flooding or cause a flood hazard to any neighboring structures. Furthermore, the Project will not affect runoff/infiltration relationships.

The Project will minimize stormwater runoff by deploying stormwater control methods described in the Environmental Guidelines (Exhibit 8). Temporary access points and any construction activities will be carefully planned and designed to utilize existing natural runoff control features, such as upland vegetated buffers, and diversion and dissipation techniques such as water bars, check dams, or settling basins. Shrubby vegetation will be retained to the extent practicable and the extent and duration of soil exposure during construction will be minimized. After construction is complete, all areas will be returned to preconstruction contours, reseeded as needed, and allowed to revegetate to a scrub-shrub condition. The Project will not alter stormwater runoff volume or direction from predevelopment conditions.

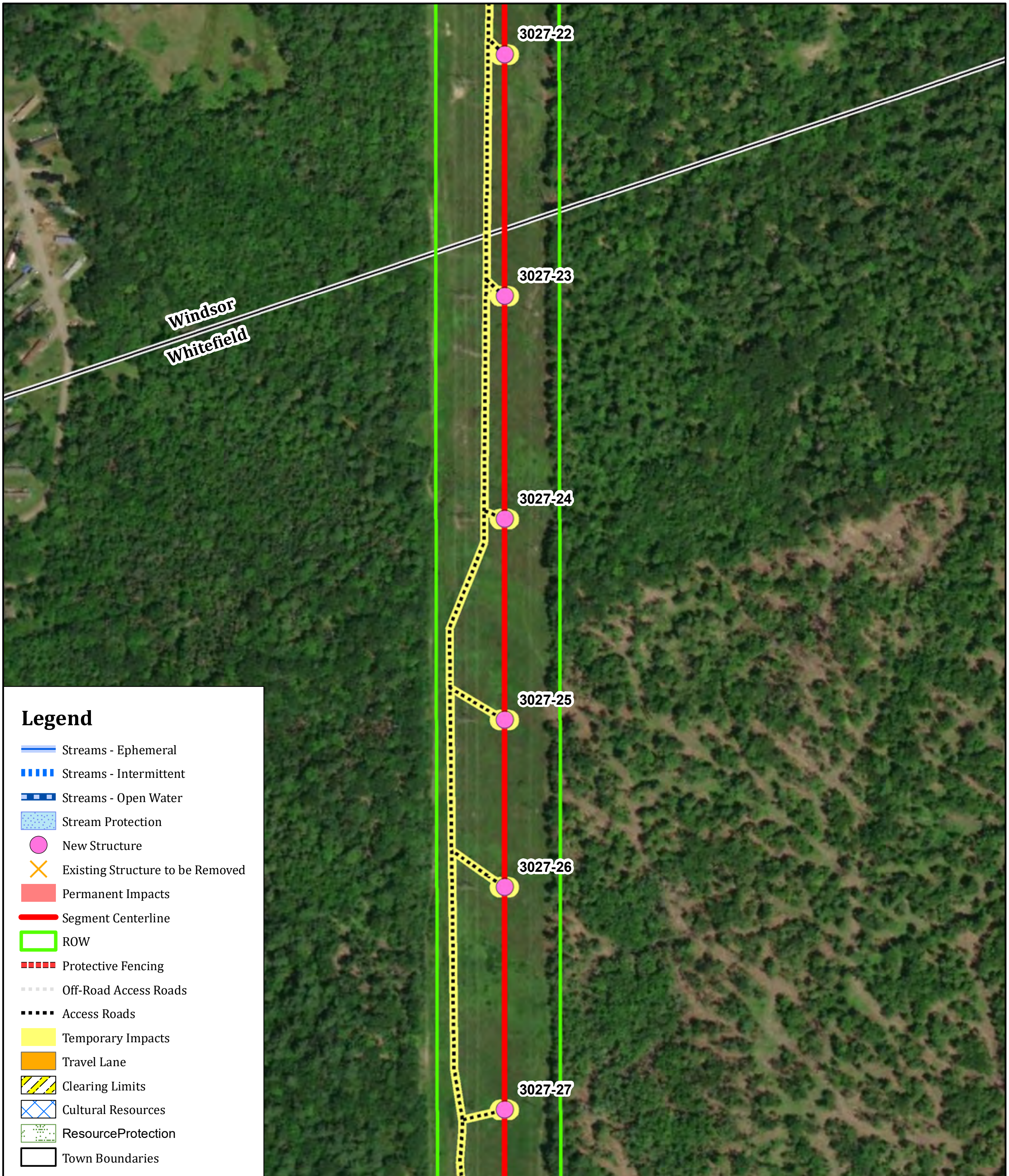
D. All proposals include base flood elevations, flood boundaries, and, in a riverine floodplain, floodway data.

The Project Scope and Natural Resource Maps (Exhibit 1) depict the FEMA flood boundaries in Whitefield. The requirement for base flood elevations apply only to the new construction or substantial improvement of "*structure*s" as defined in the FMO. The transmission line poles do not meet this definition and it is therefore not required.

E. Any proposed development plan must include a condition of plan approval requiring that structures on any lot in the development having any portion of its land within a Special Flood Hazard Area, are to be constructed in accordance with Article VI of this ordinance.

Not applicable. The proposed Project does not include "structures" as defined in the FMO. Nevertheless, the Project's compliance with the Article VI Development Standards is presented in the preceding section of this application.

EXHIBIT 1 PROJECT SCOPE AND NATURAL RESOURCE MAPS



Legend

- Streams - Ephemeral
- Streams - Intermittent
- Streams - Open Water
- Stream Protection
- New Structure
- Existing Structure to be Removed
- Permanent Impacts
- Segment Centerline
- ROW
- Protective Fencing
- Off-Road Access Roads
- Access Roads
- Temporary Impacts
- Travel Lane
- Clearing Limits
- Cultural Resources
- ResourceProtection
- Town Boundaries

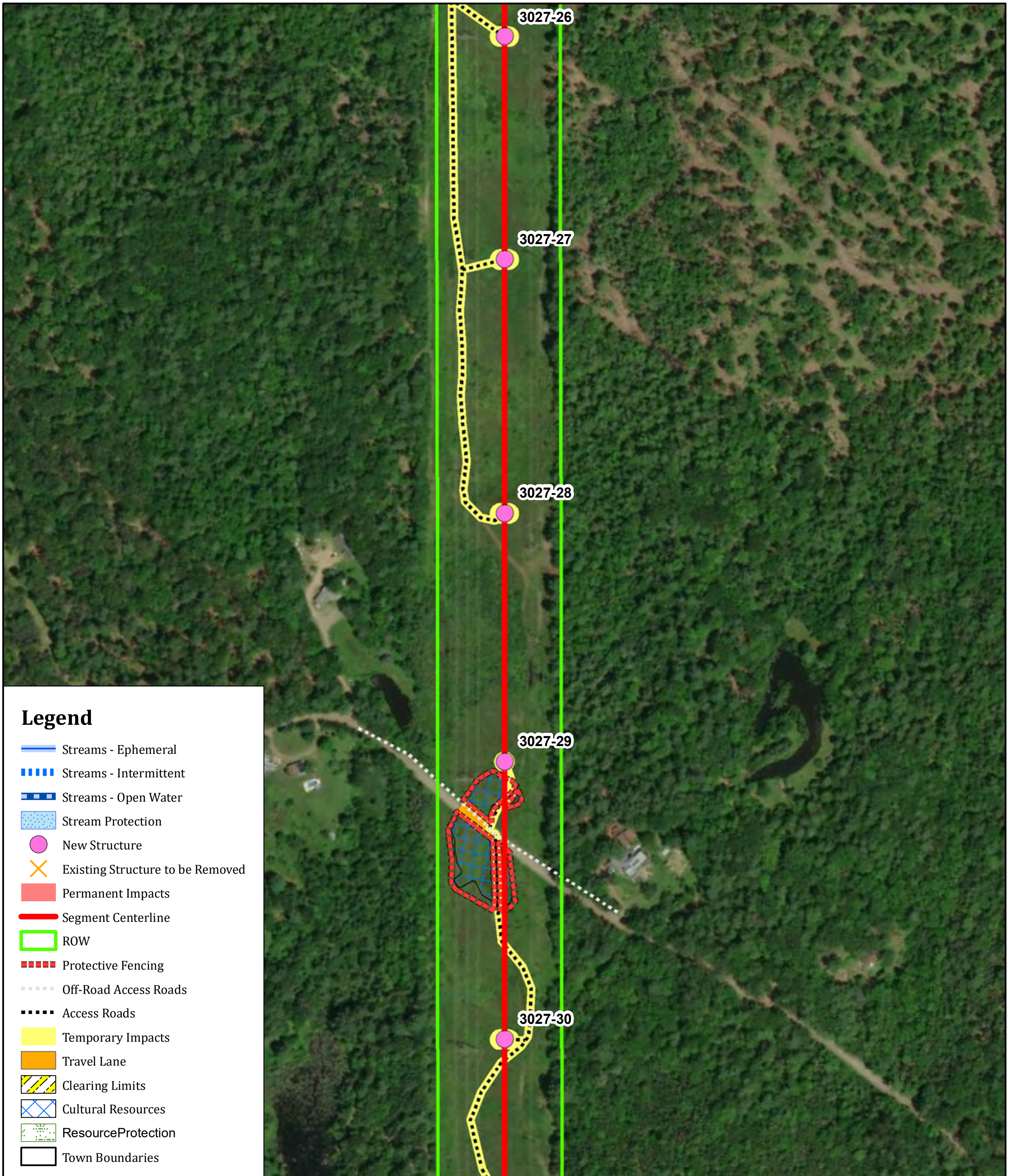
N

0 100 200 Feet

BLACK & VEATCH

Natural Resource Map
Whitefield, Maine

9/30/2020



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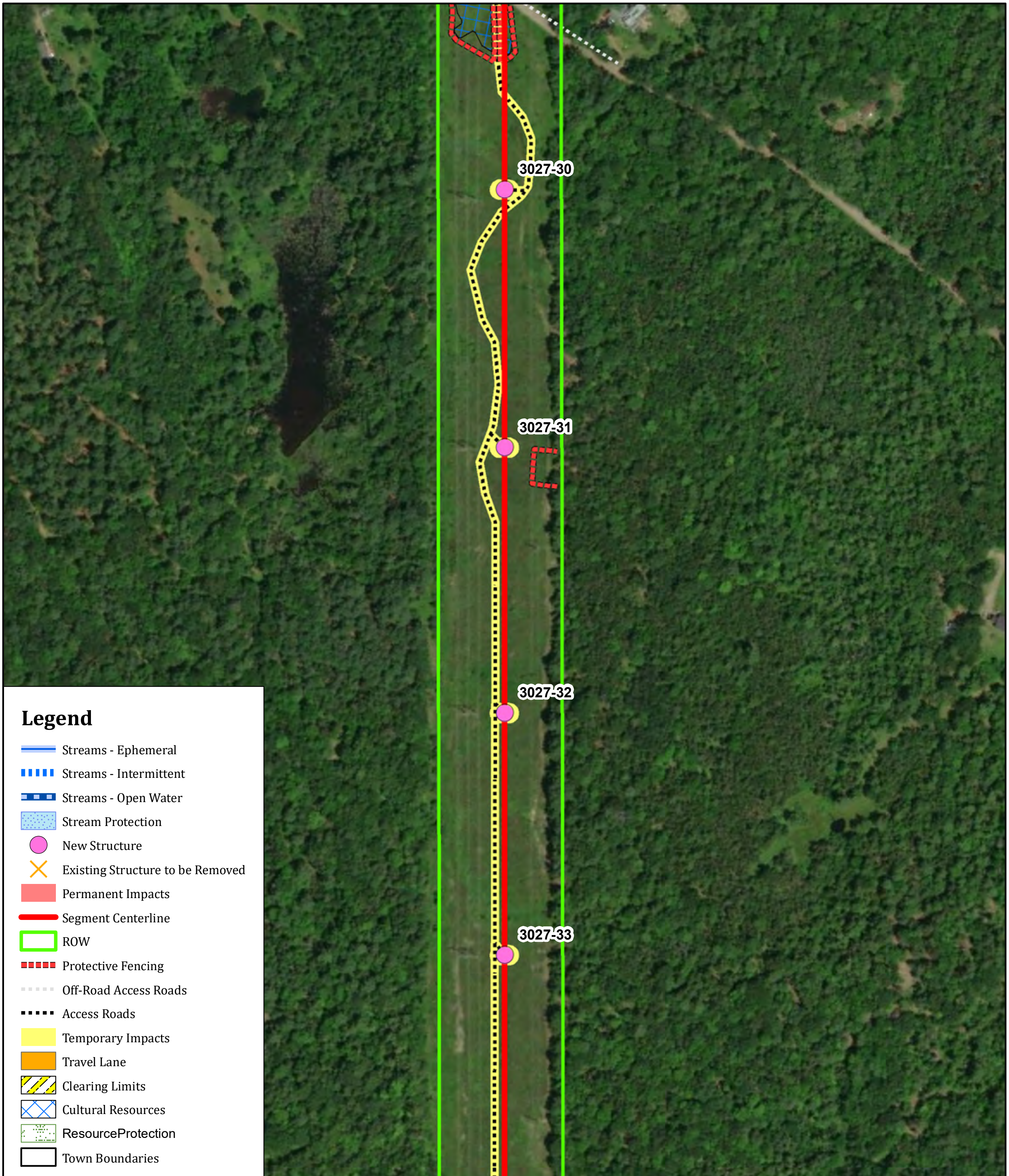
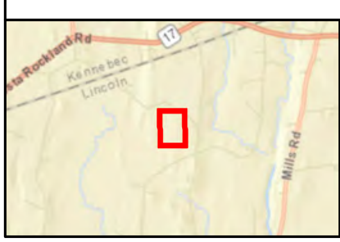
Natural Resource Map
Whitefield, Maine

10/1/2020





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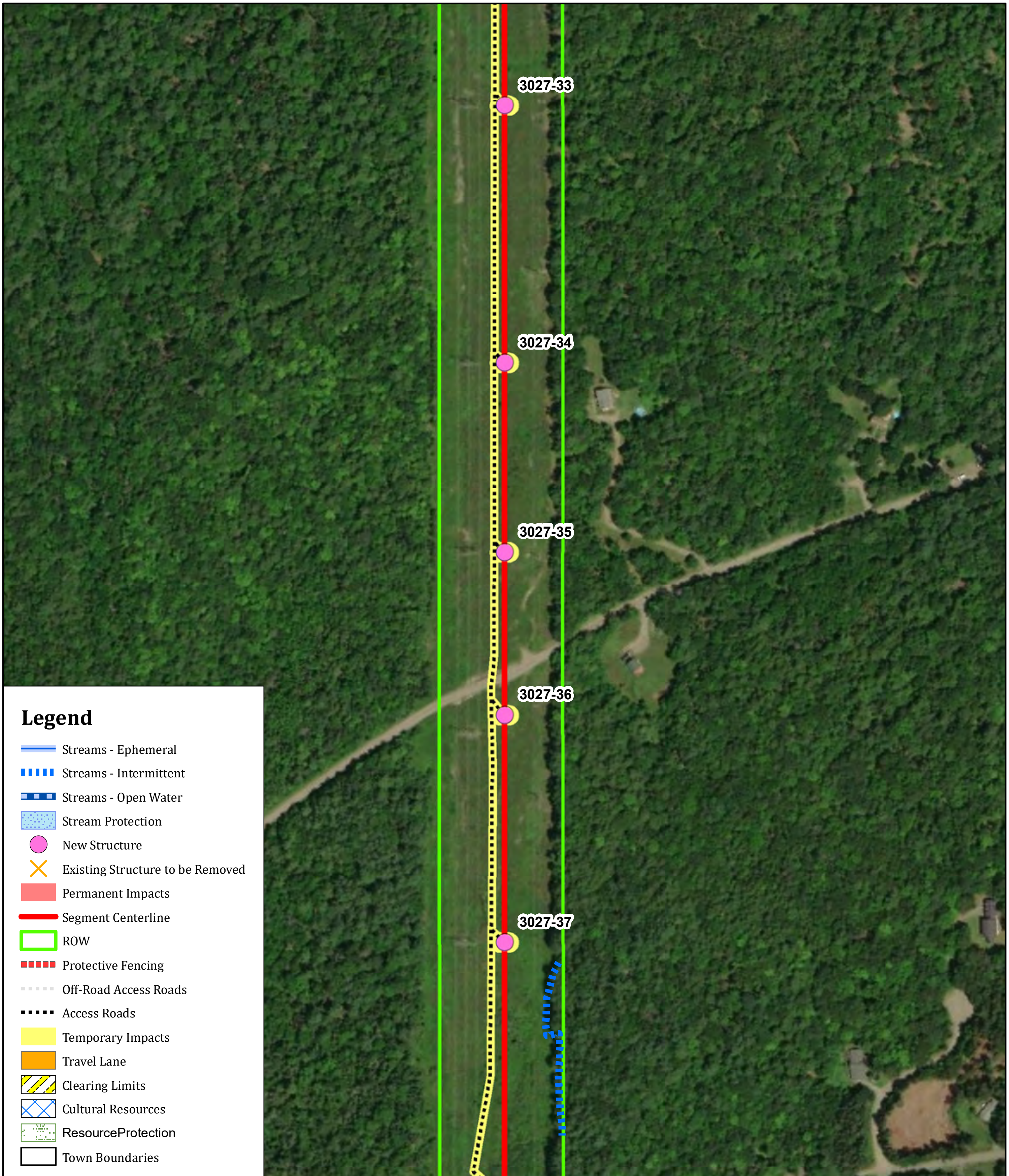

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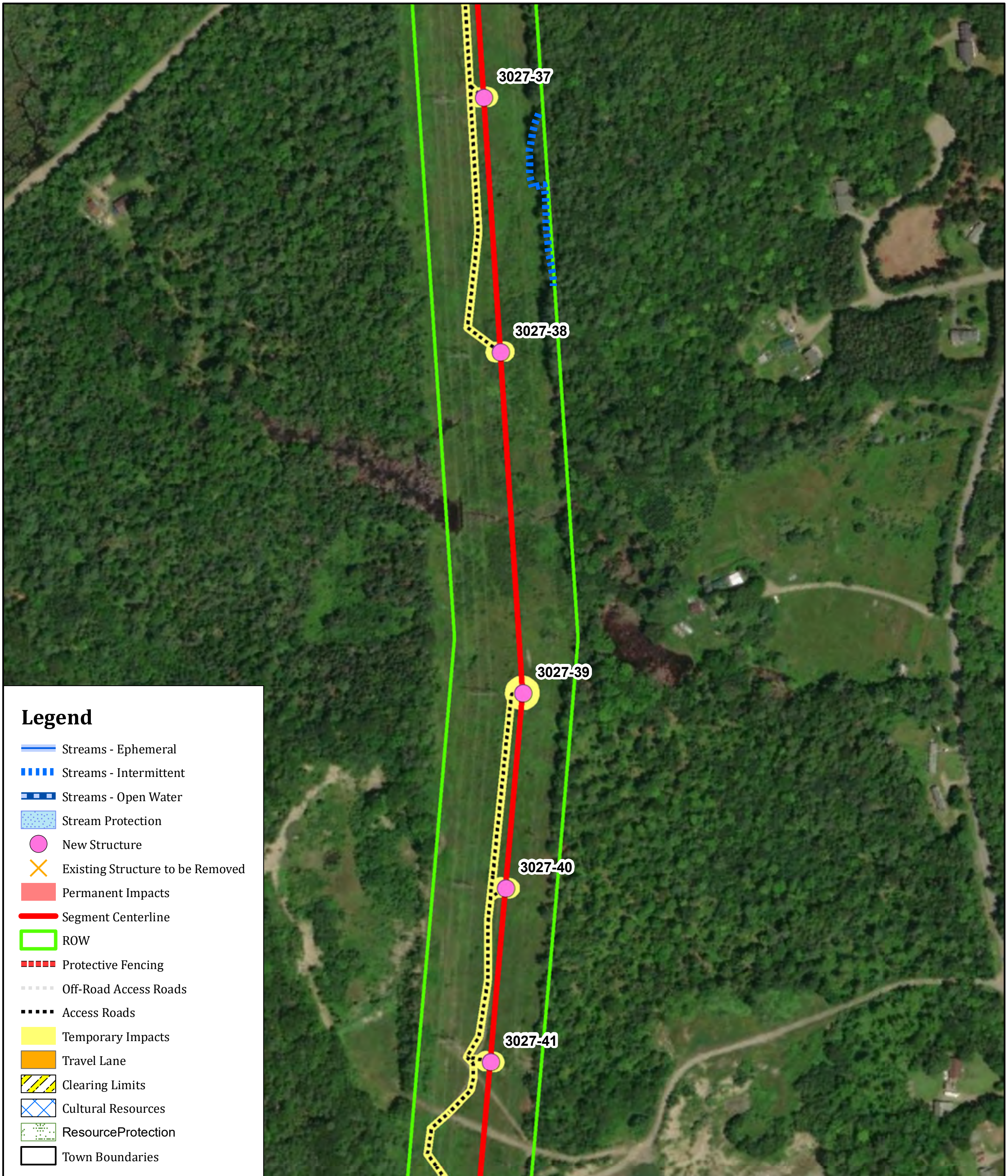

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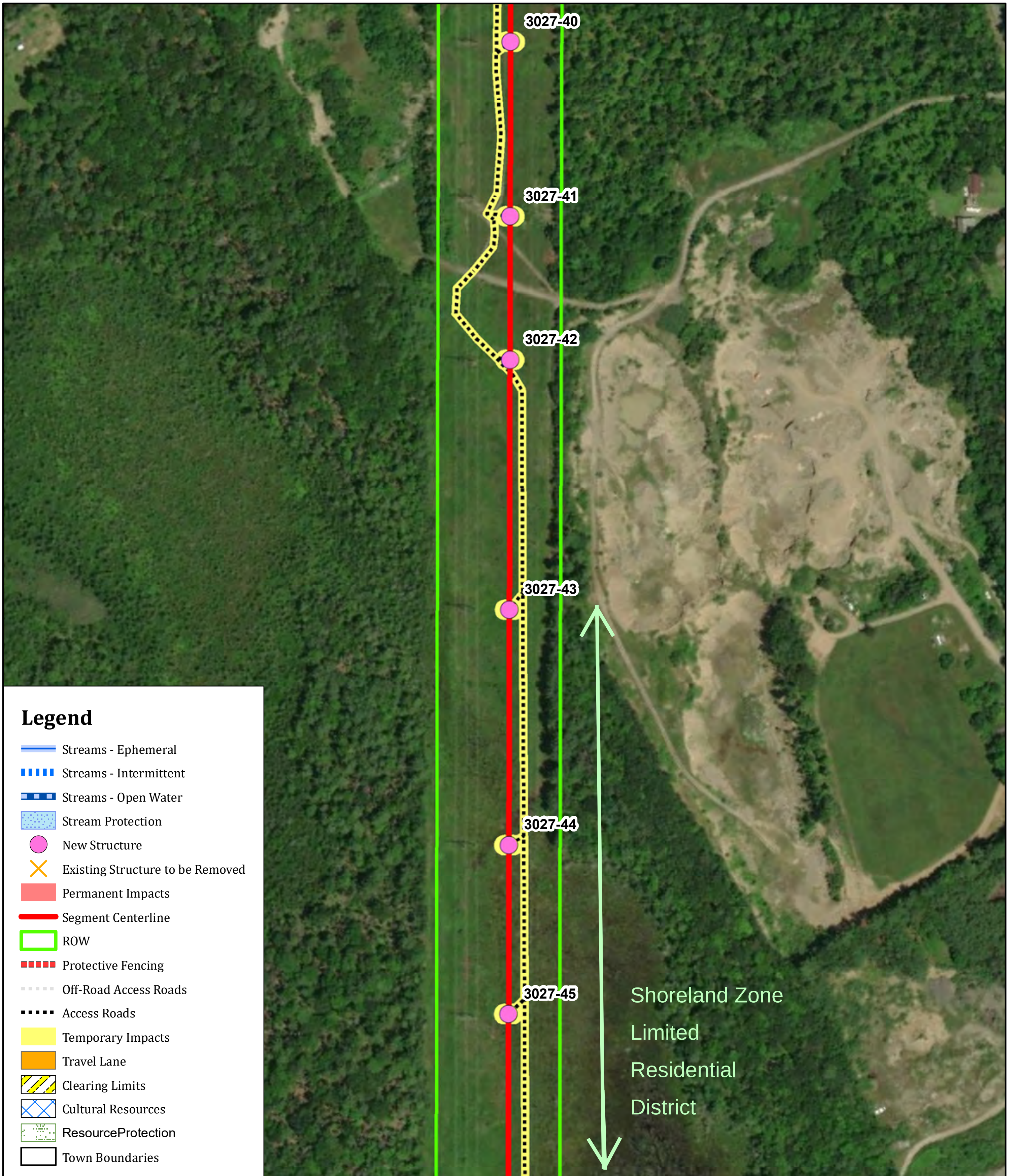

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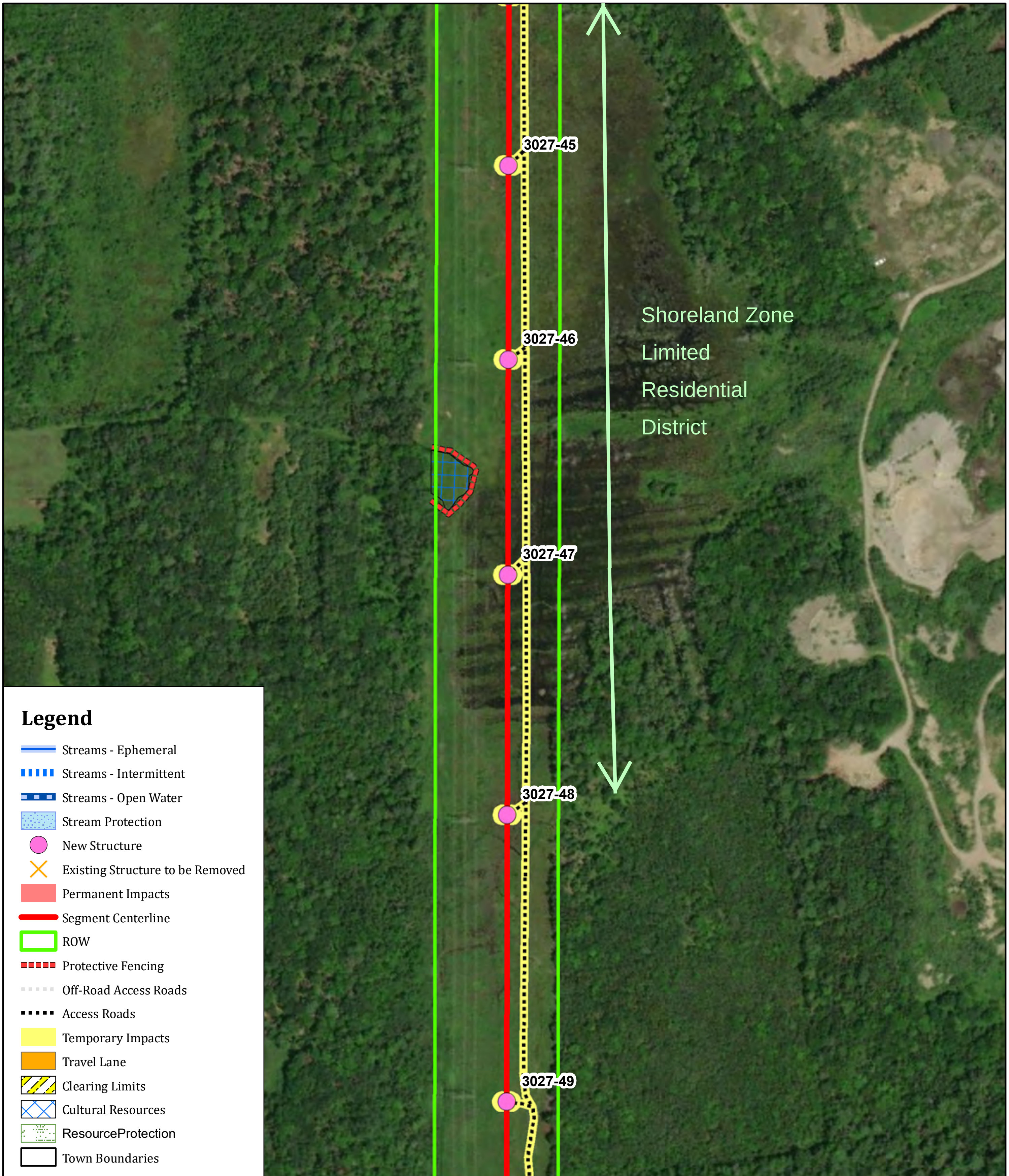

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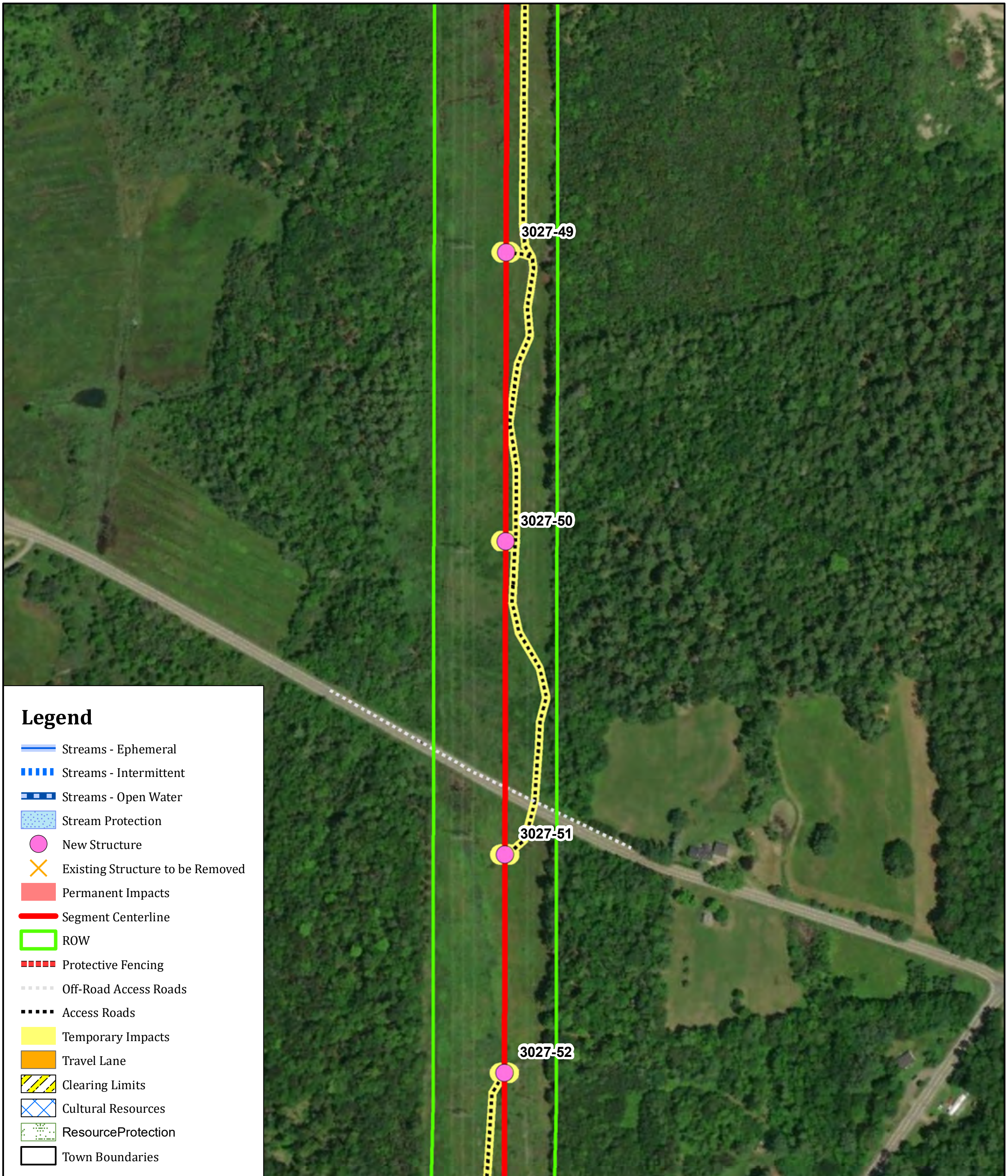

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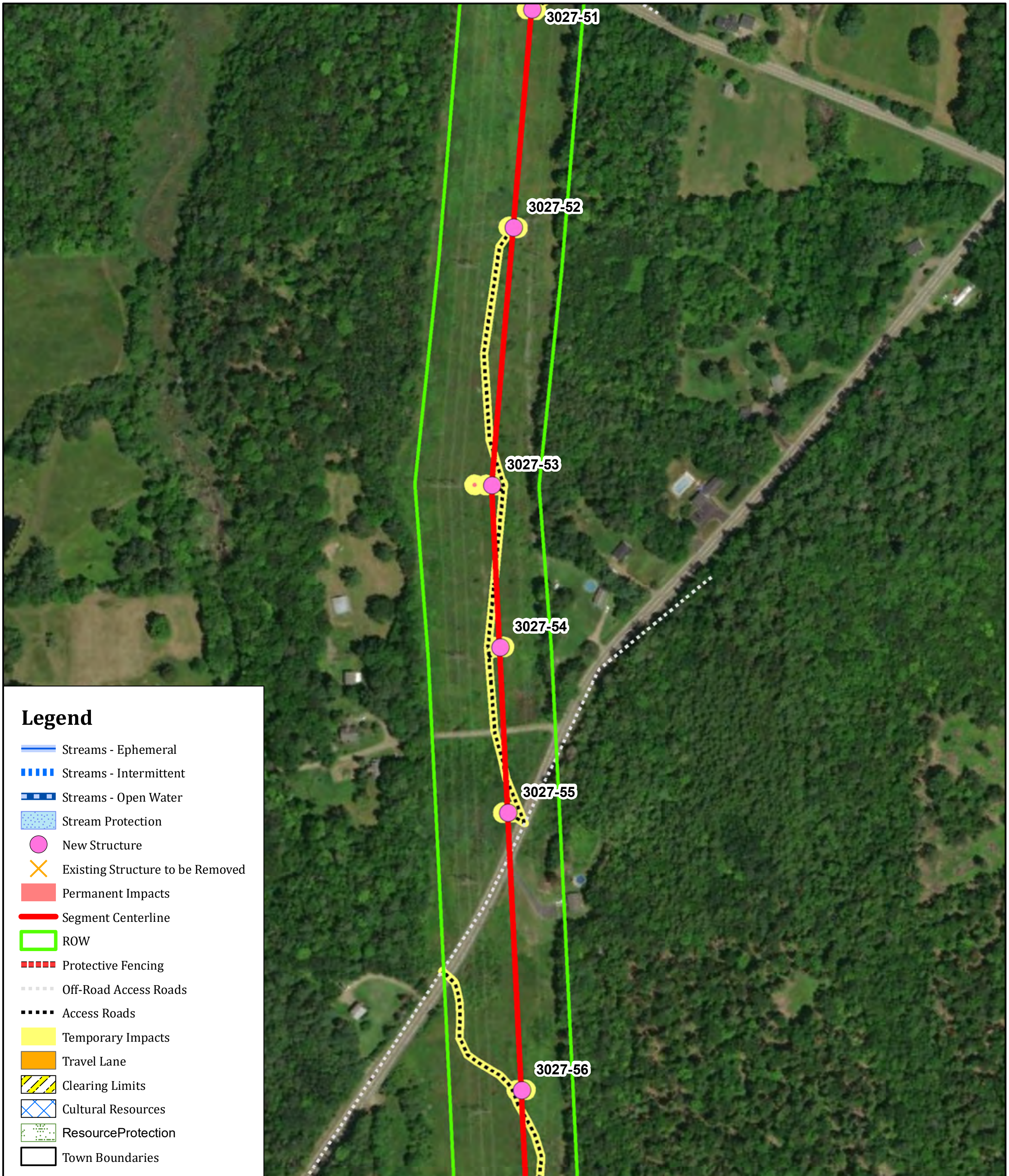

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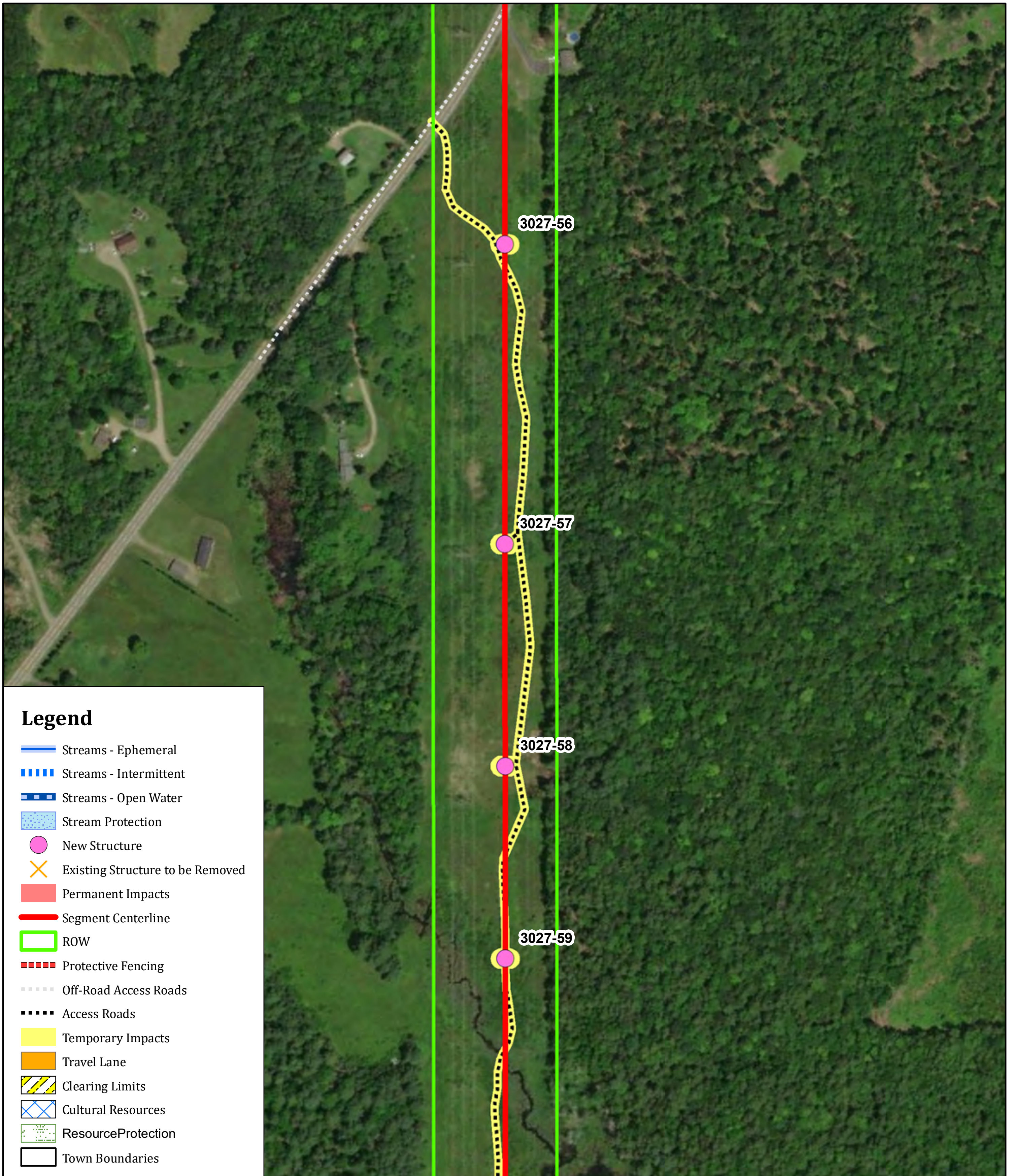

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Whitefield, Maine

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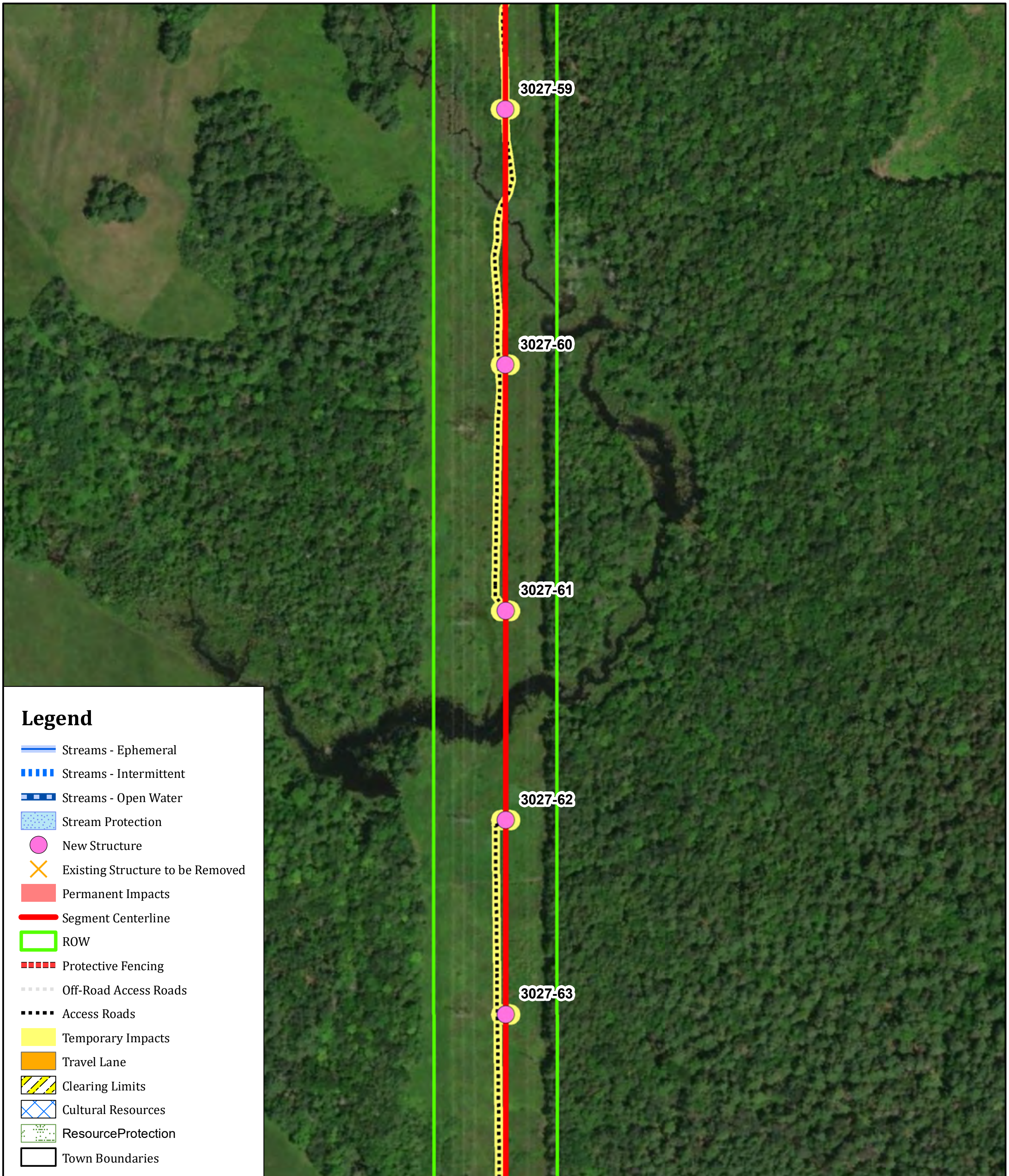

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Natural Resource Map
Whitefield, Maine

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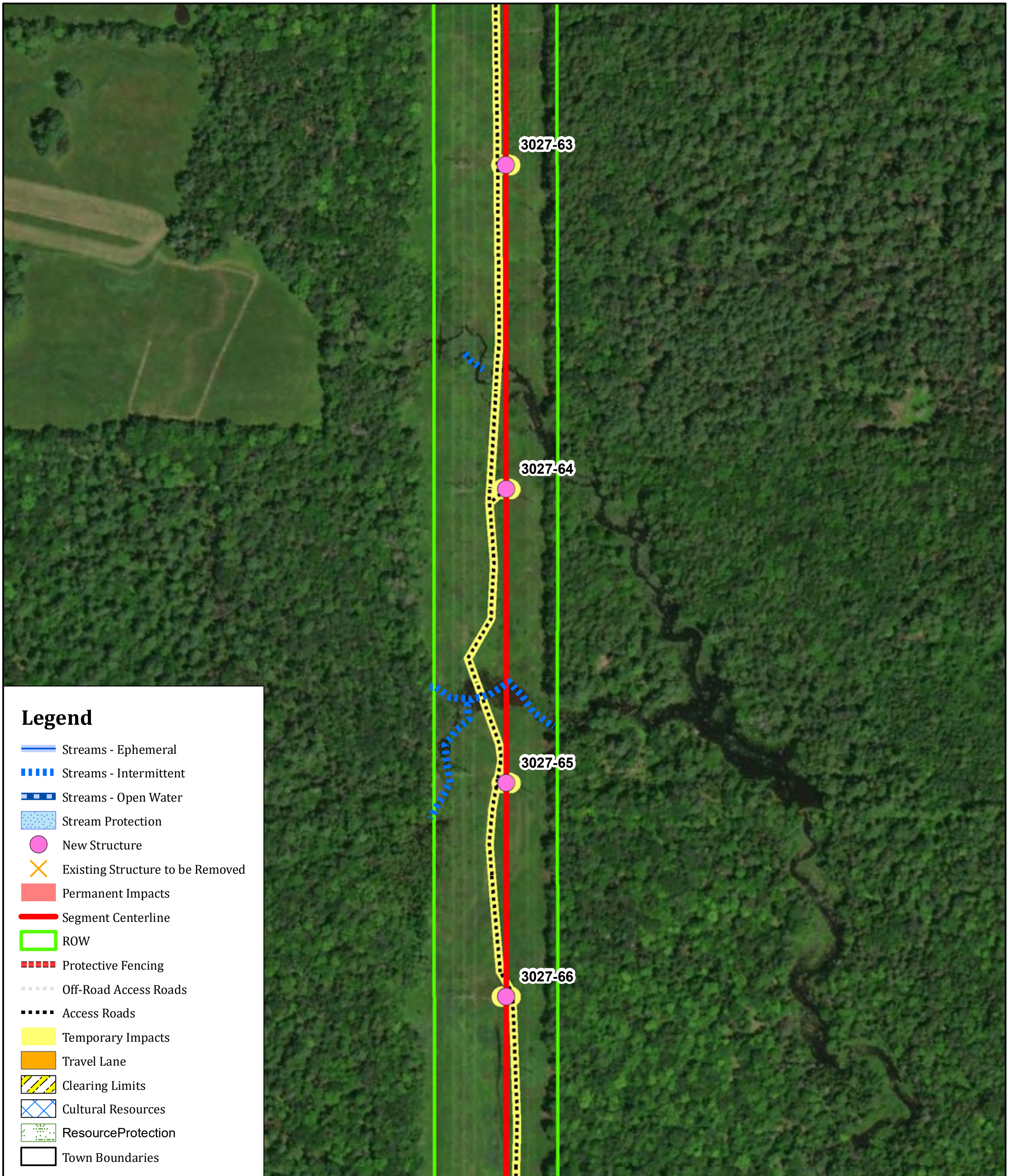
9/30/2020



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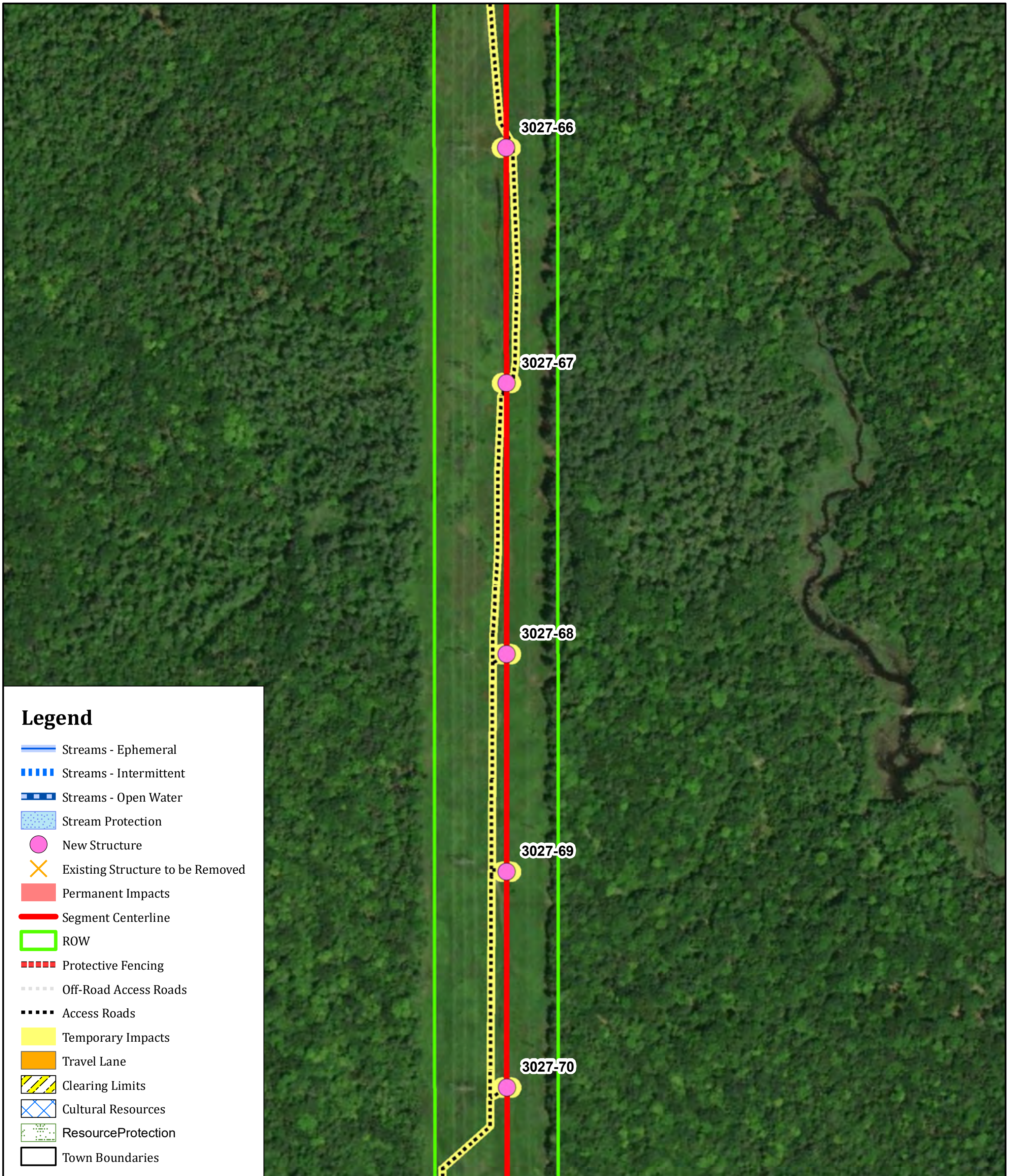
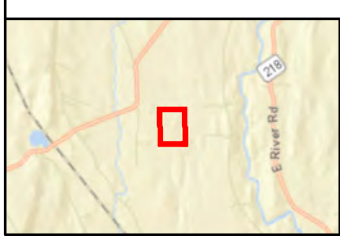
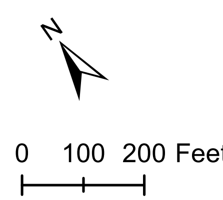
Natural Resource Map
Whitefield, Maine

9/30/2020







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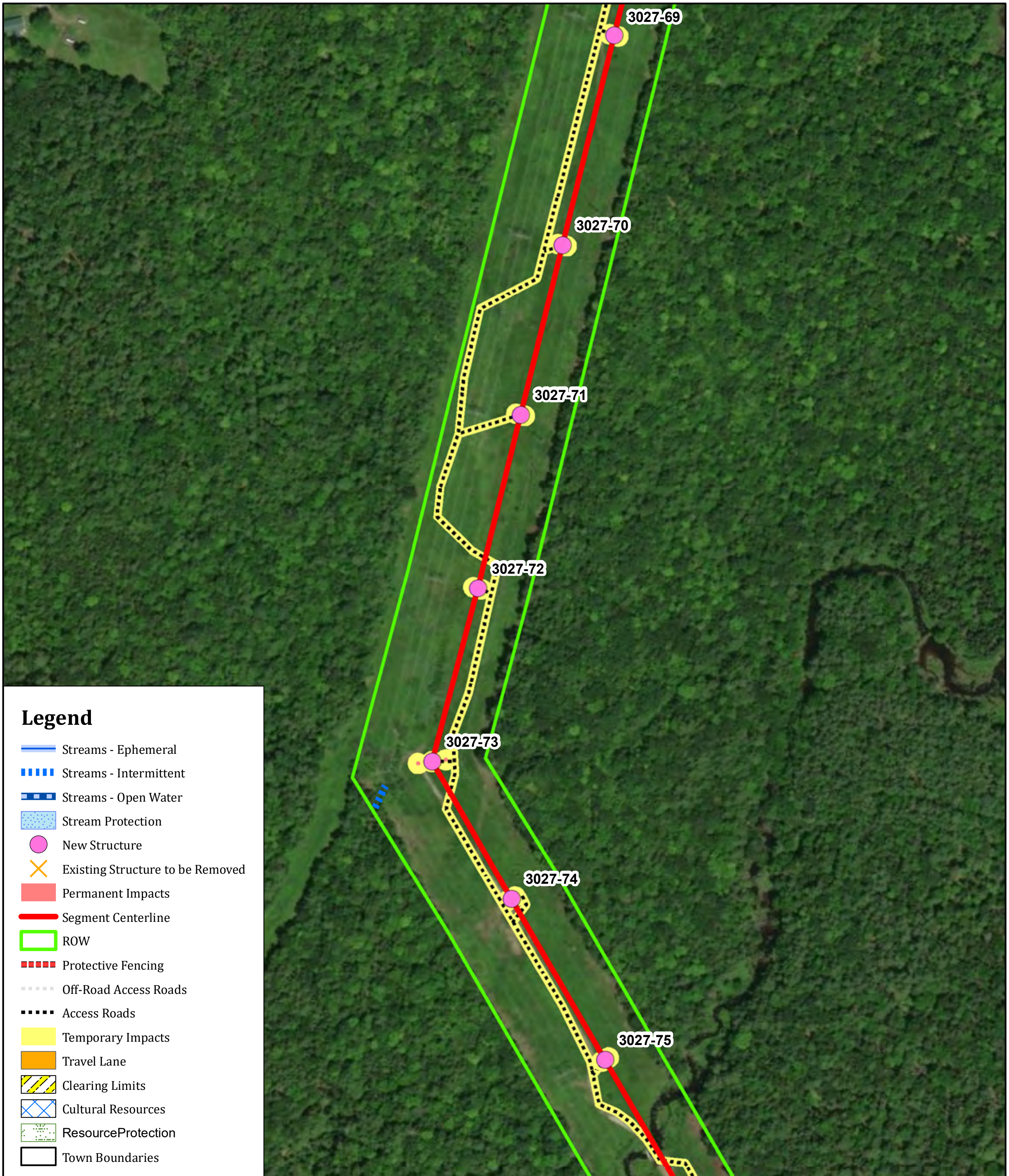
9/30/2020



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Natural Resource Map
Whitefield, Maine

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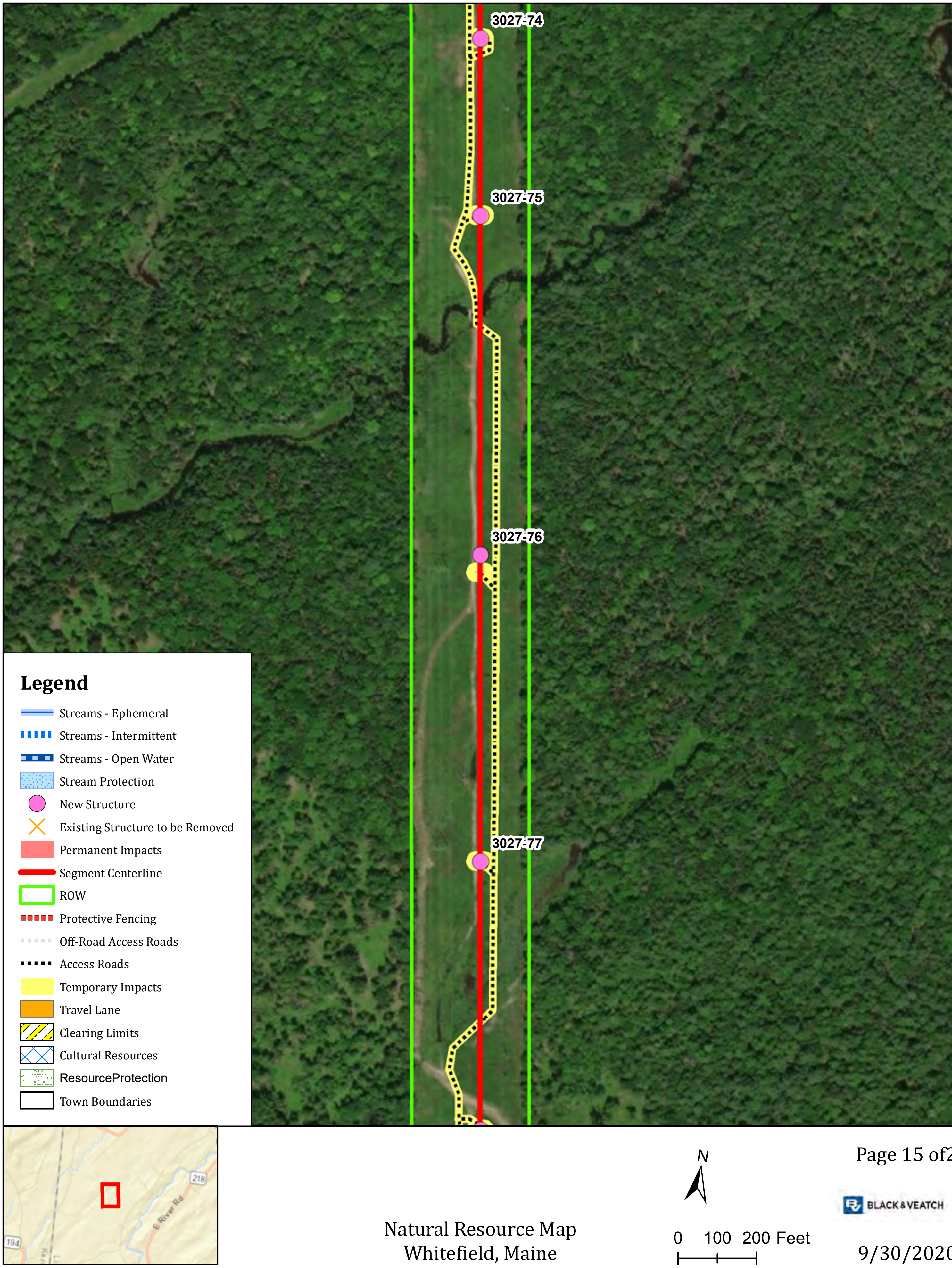
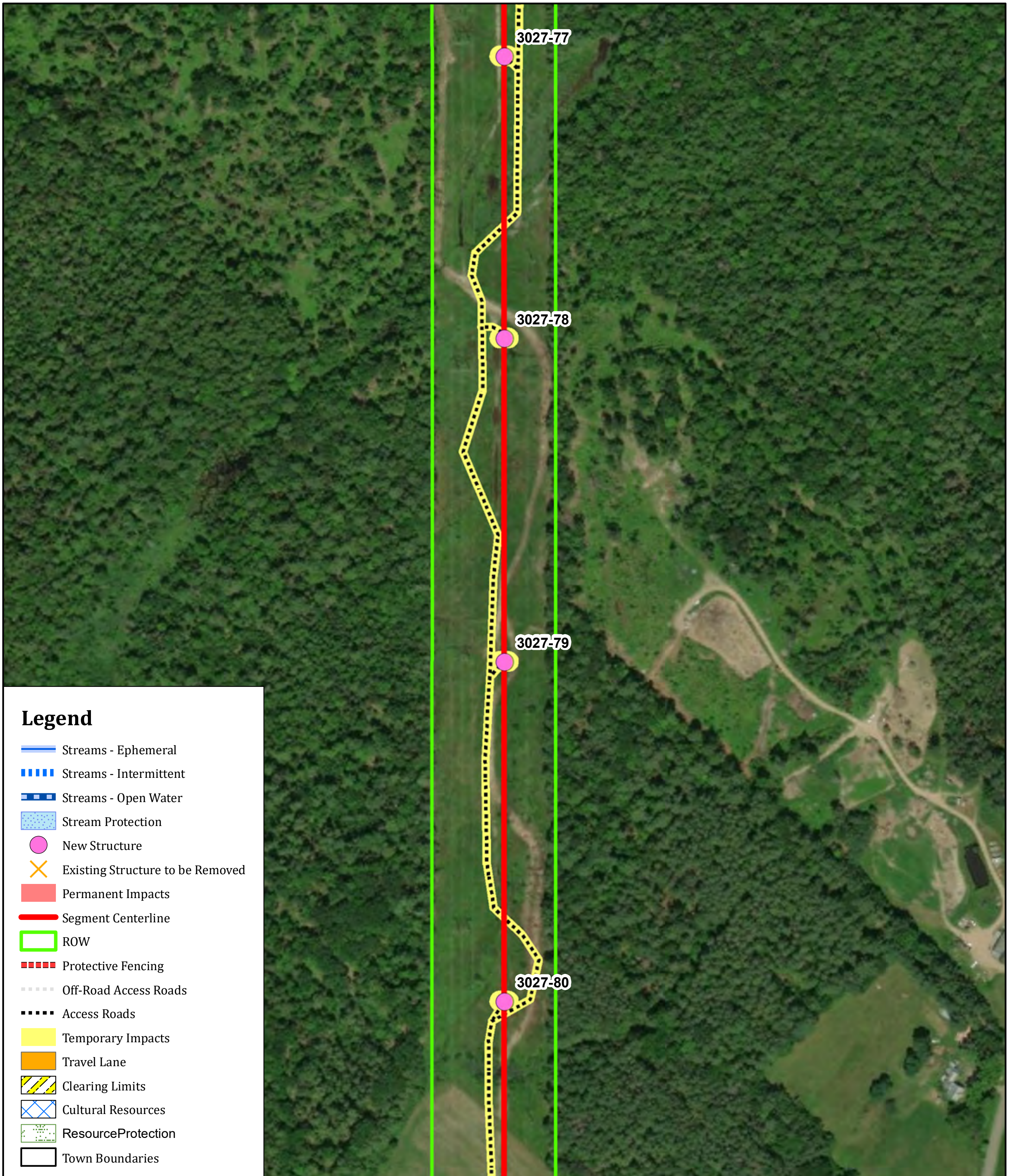
BLACK & VEATCH

9/30/2020



Natural Resource Map
Whitefield, Maine

9/30/2020



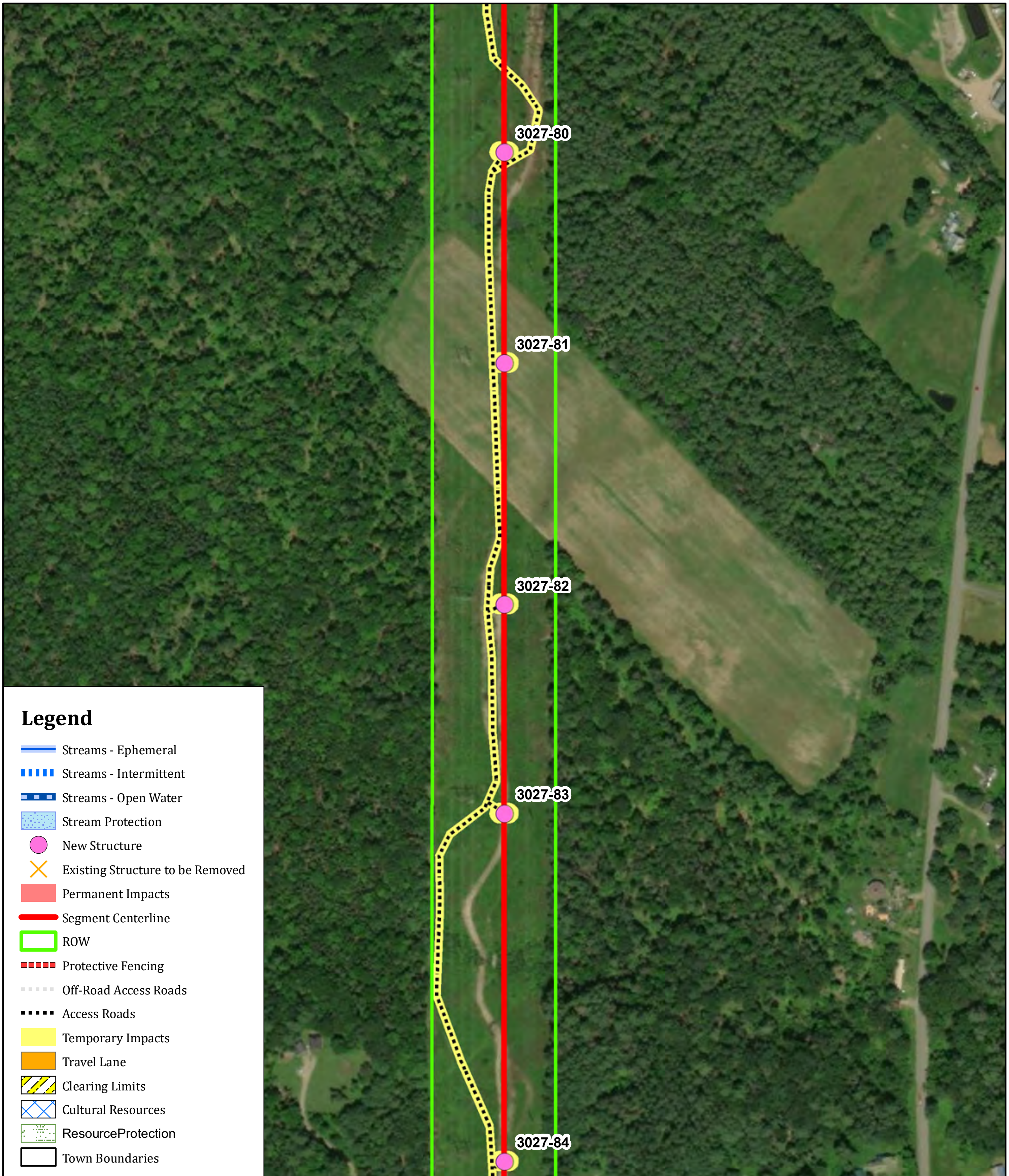
N

0 100 200 Feet

Natural Resource Map
Whitefield, Maine

BLACK & VEATCH

9/30/2020



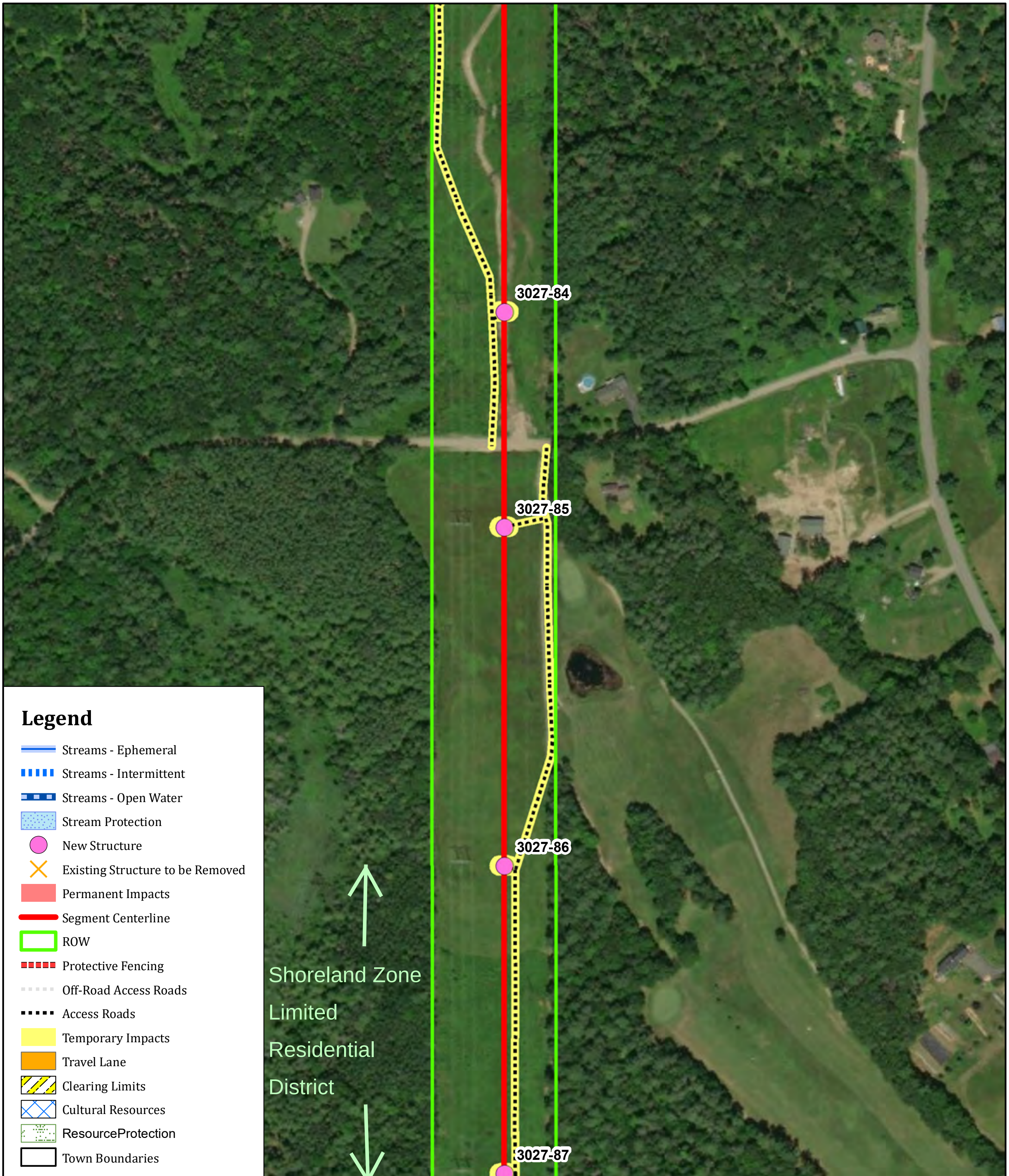
N

0 100 200 Feet

Natural Resource Map
Whitefield, Maine

BLACK & VEATCH

9/30/2020



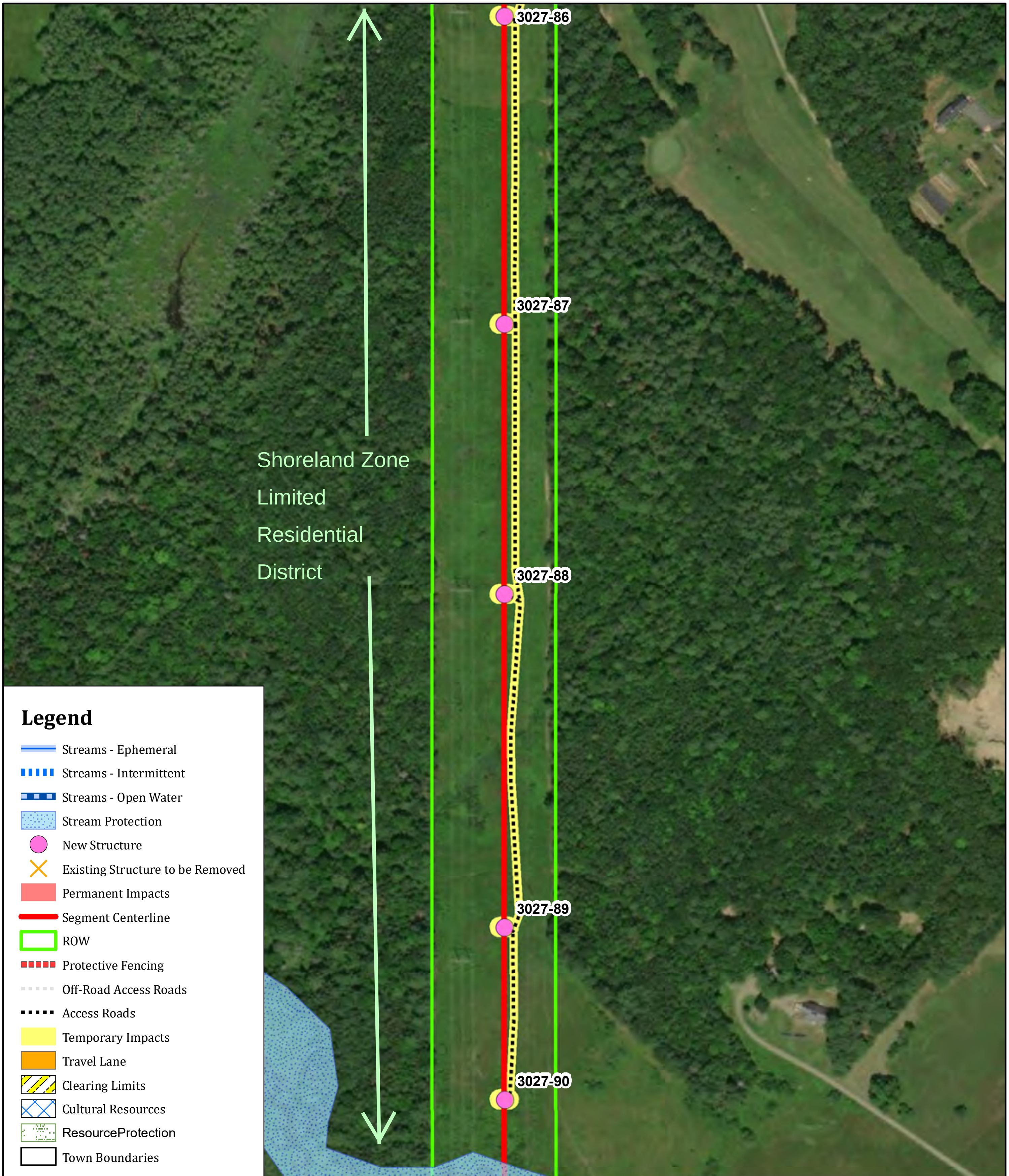
New England
Clean Energy Connect
Natural Resource Map
Whitefield, Maine

N

0 100 200 Feet

BLACK & VEATCH

9/30/2020



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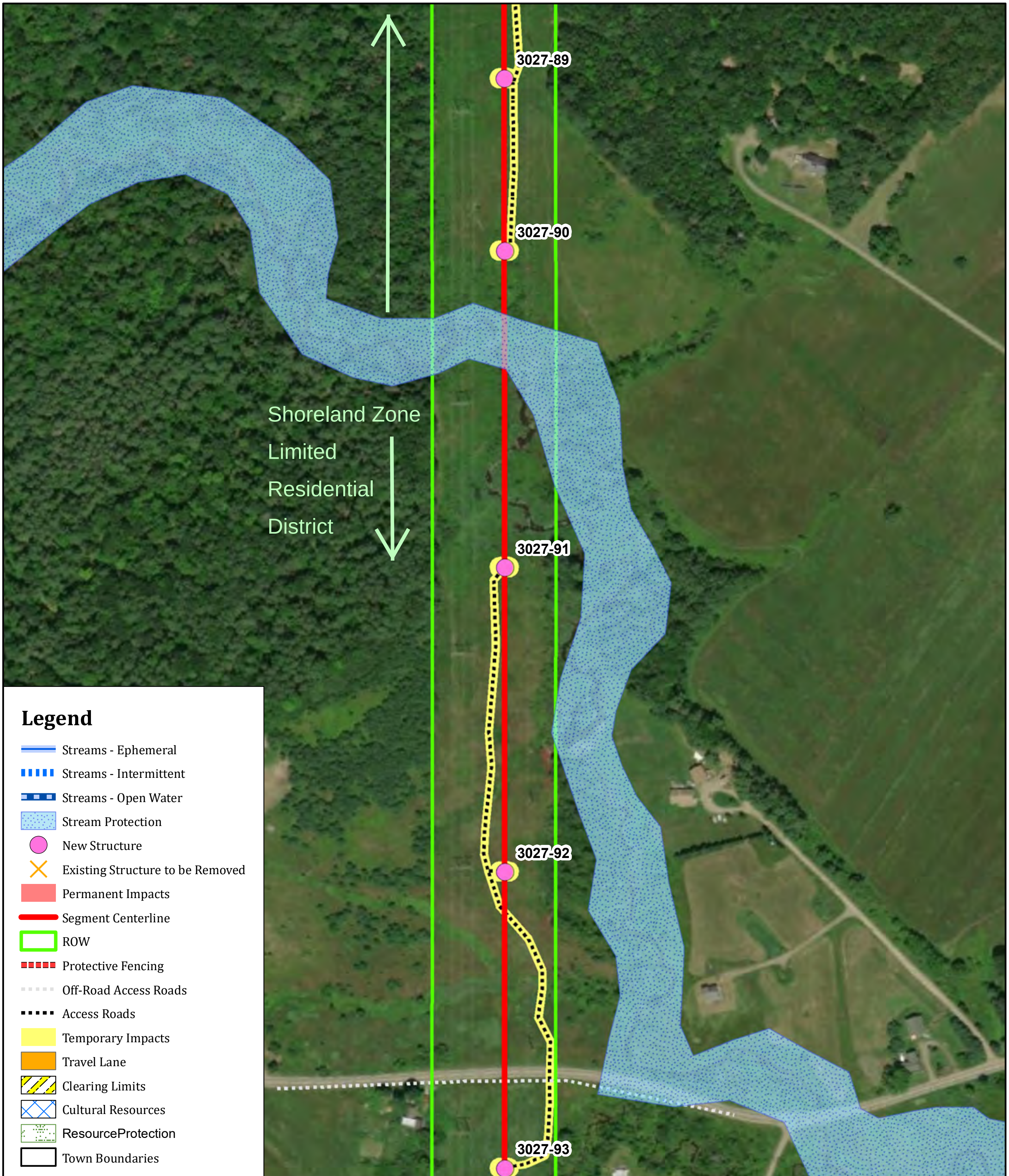
0 100 200 Feet

Natural Resource Map
Whitefield, Maine

9/30/2020



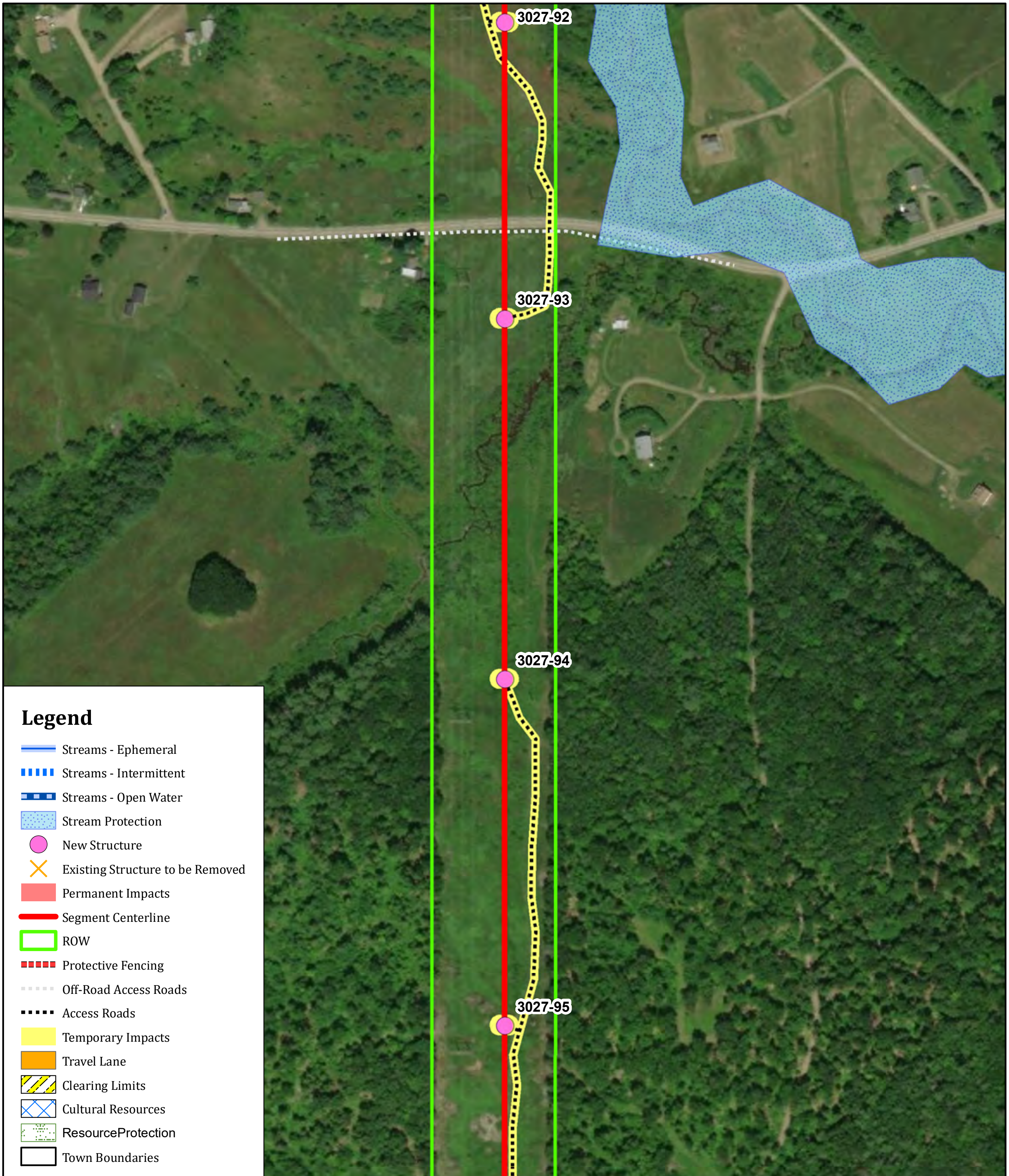
N

0 100 200 Feet

Natural Resource Map
Whitefield, Maine

BLACK & VEATCH

9/30/2020



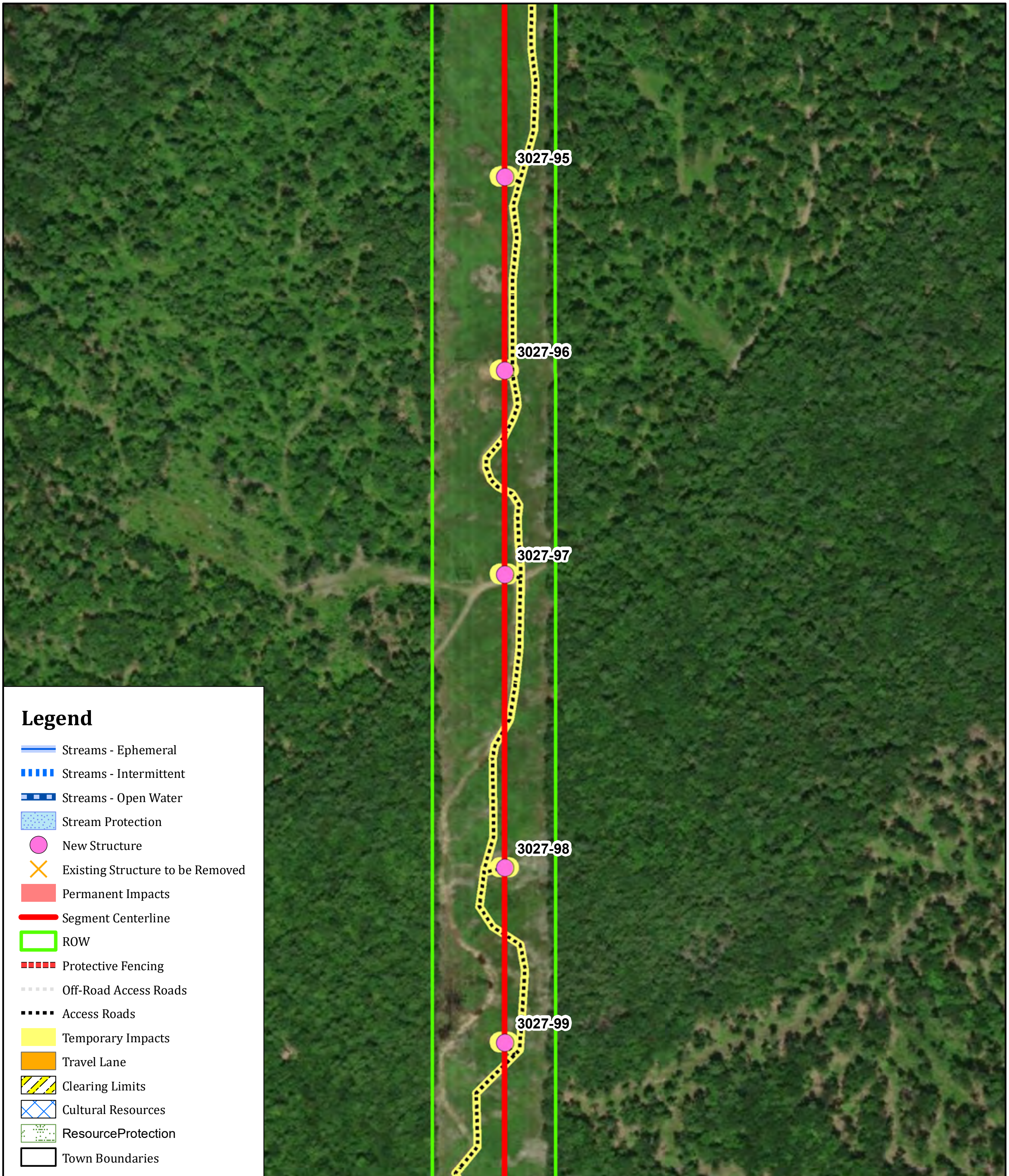
Natural Resource Map
Whitefield, Maine

N

0 100 200 Feet

BLACK & VEATCH

9/30/2020

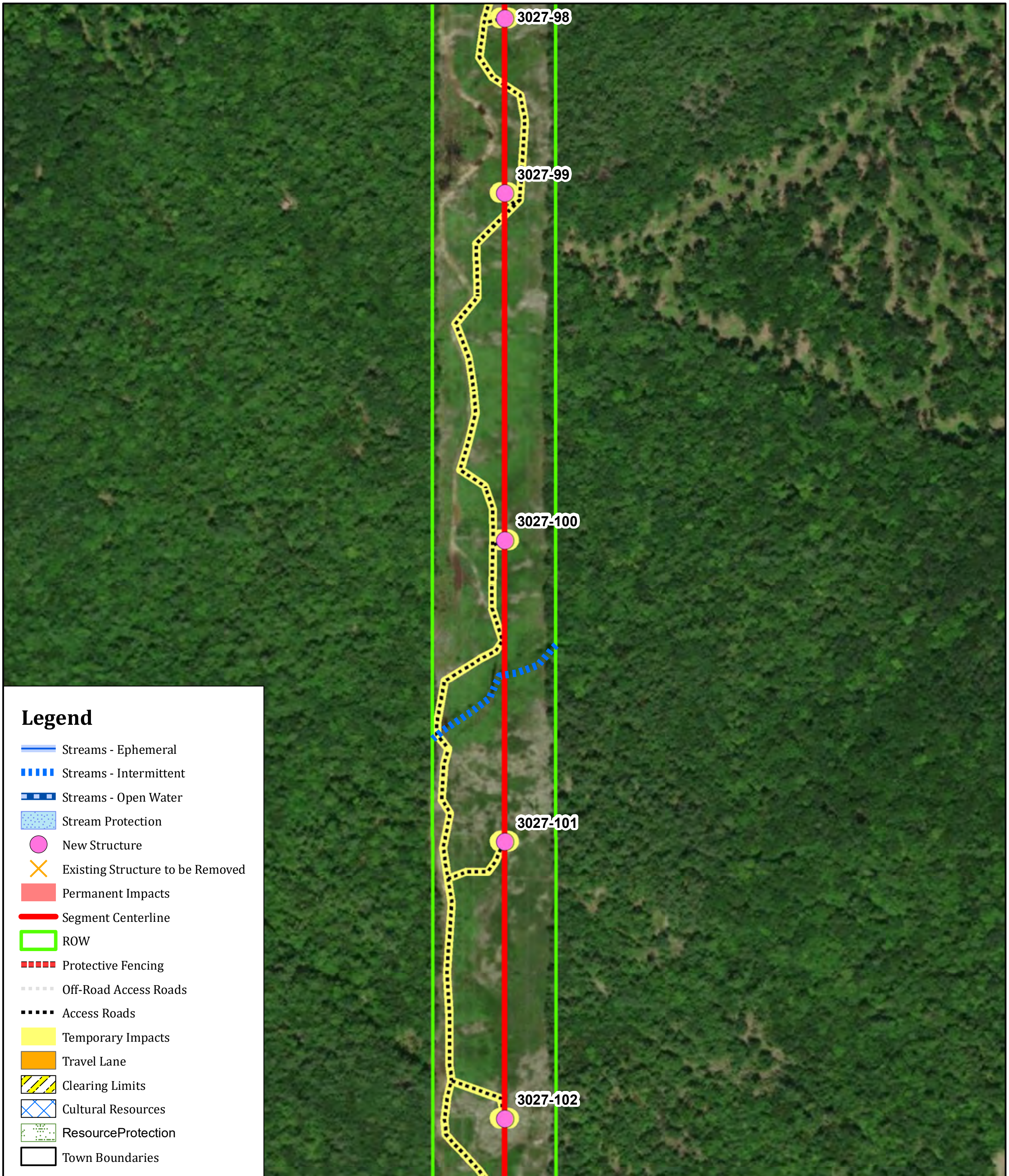


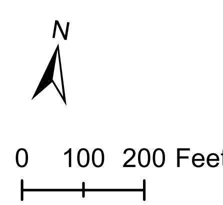
N

0 100 200 Feet

Natural Resource Map
Whitefield, Maine

9/30/2020

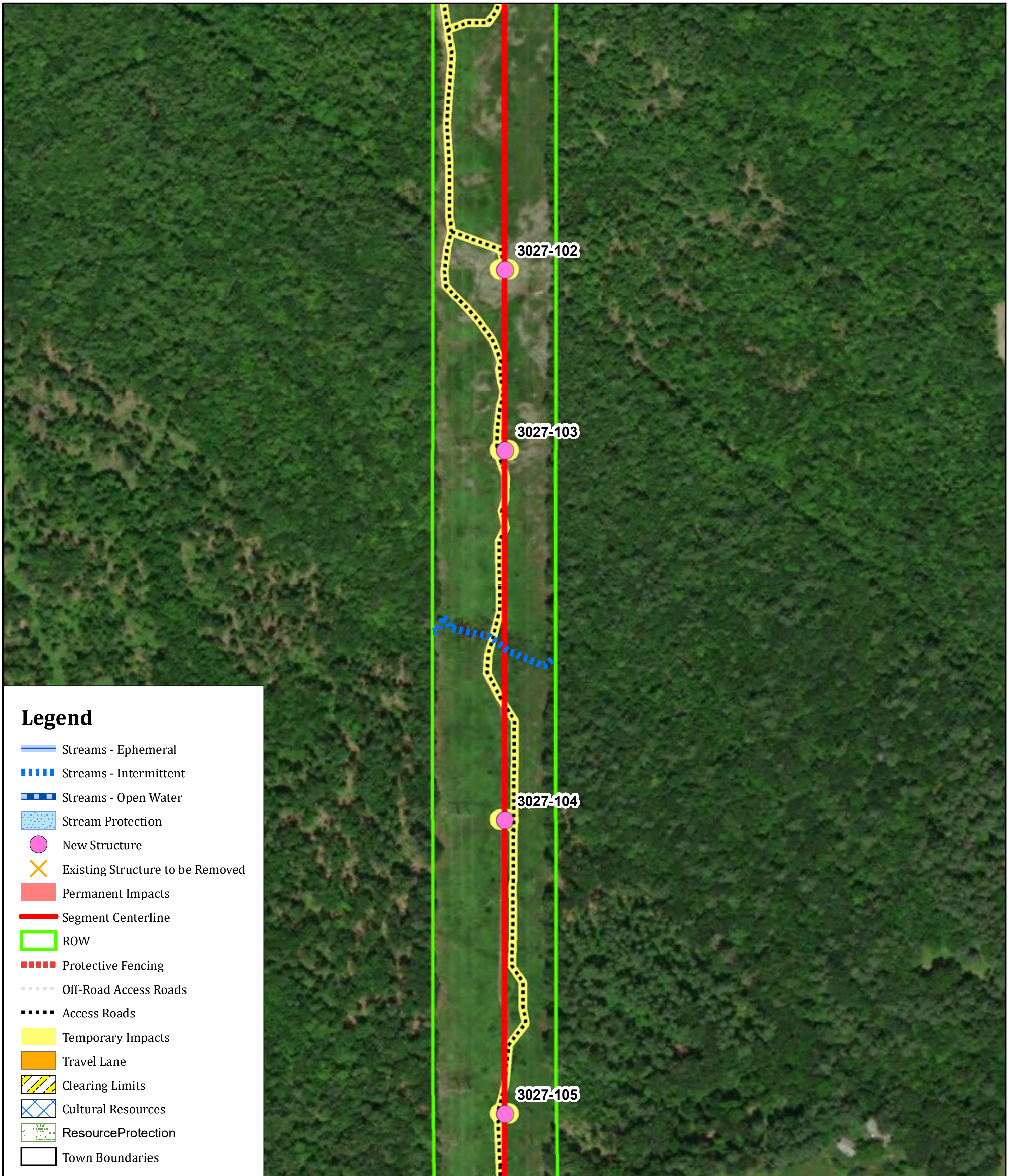




BLACK & VEATCH

Natural Resource Map
Whitefield, Maine

9/30/2020



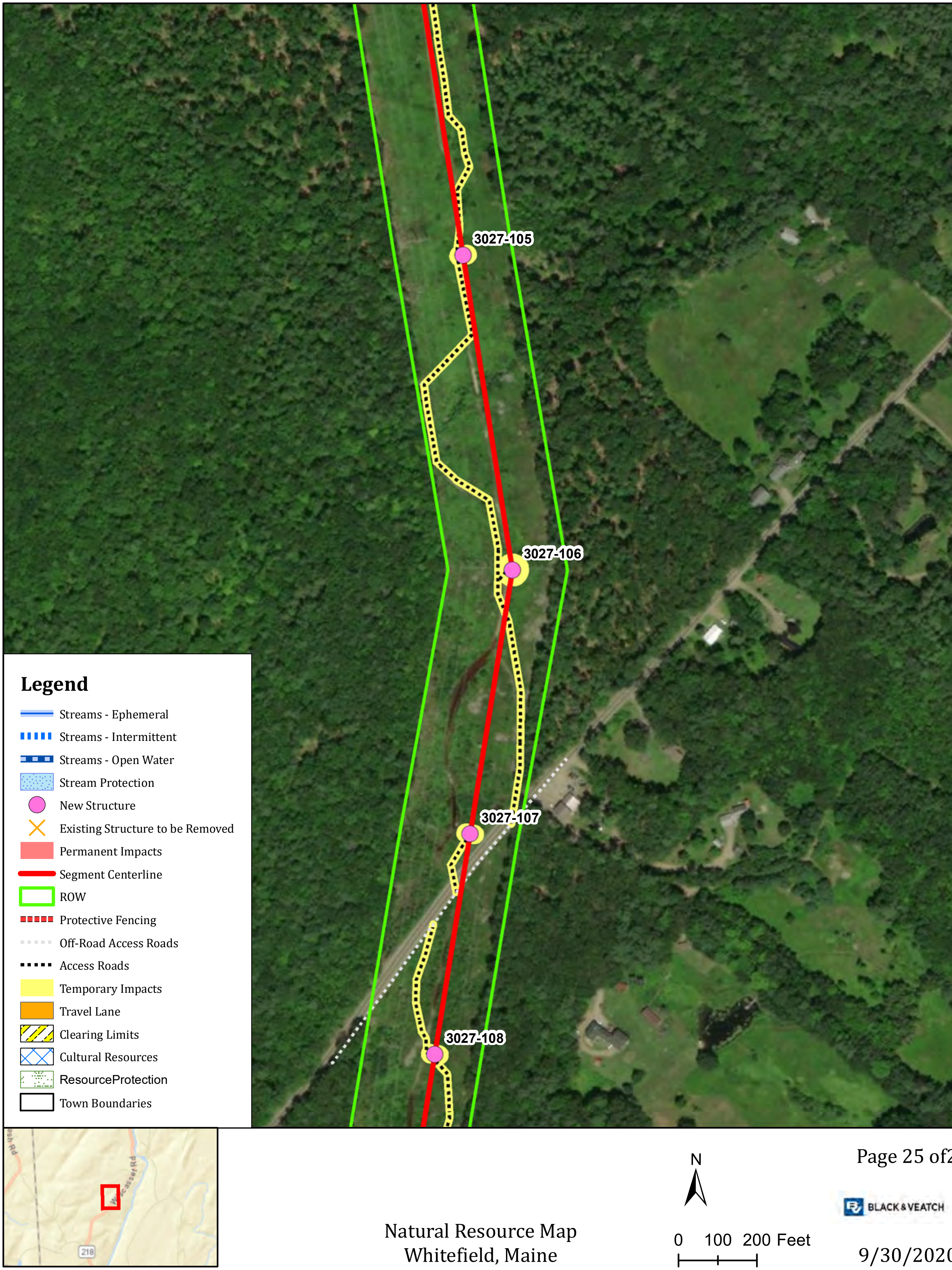
N

0 100 200 Feet

Natural Resource Map
Whitefield, Maine

BLACK & VEATCH

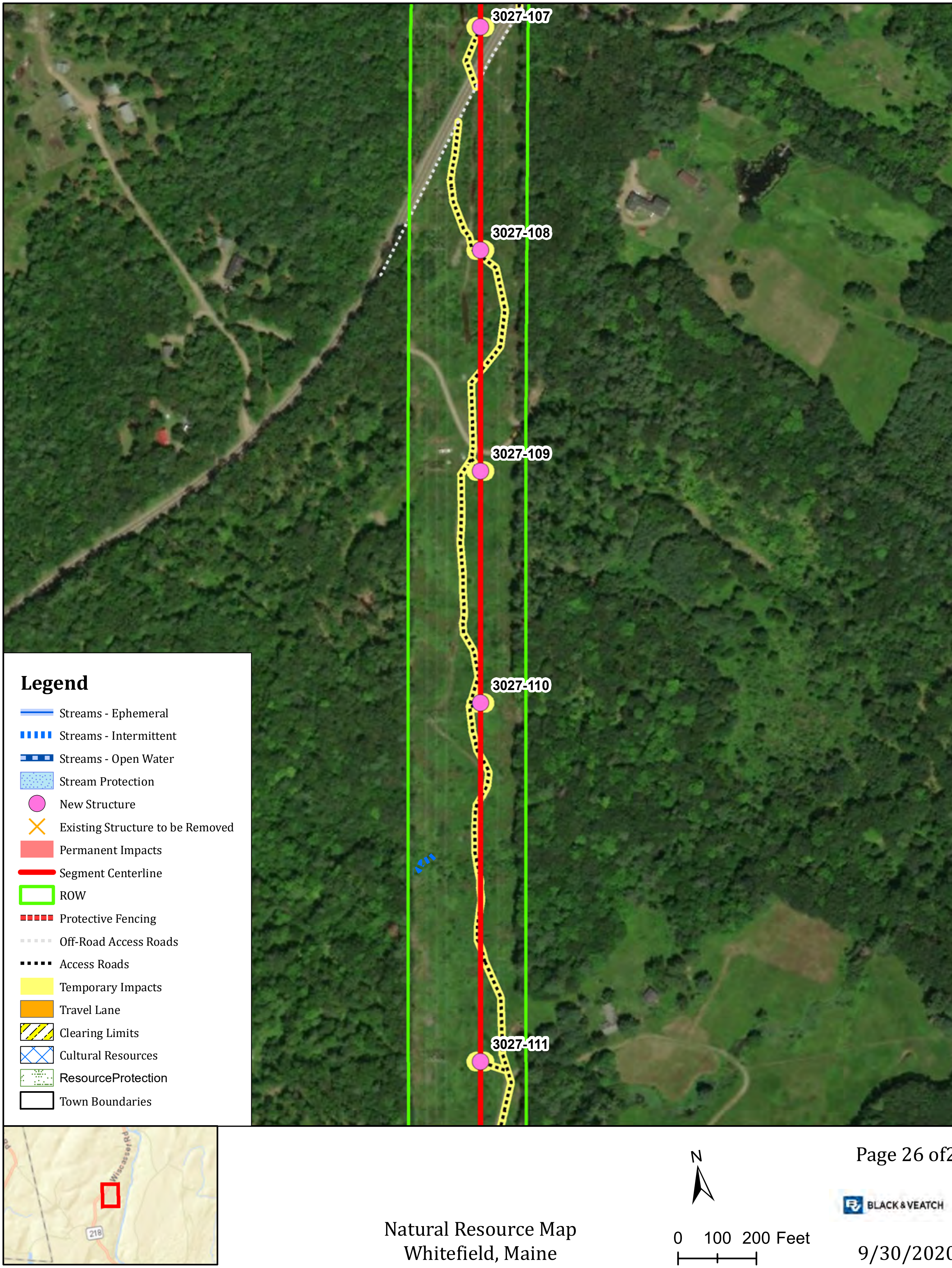
9/30/2020



BLACK & VEATCH

Natural Resource Map
Whitefield, Maine

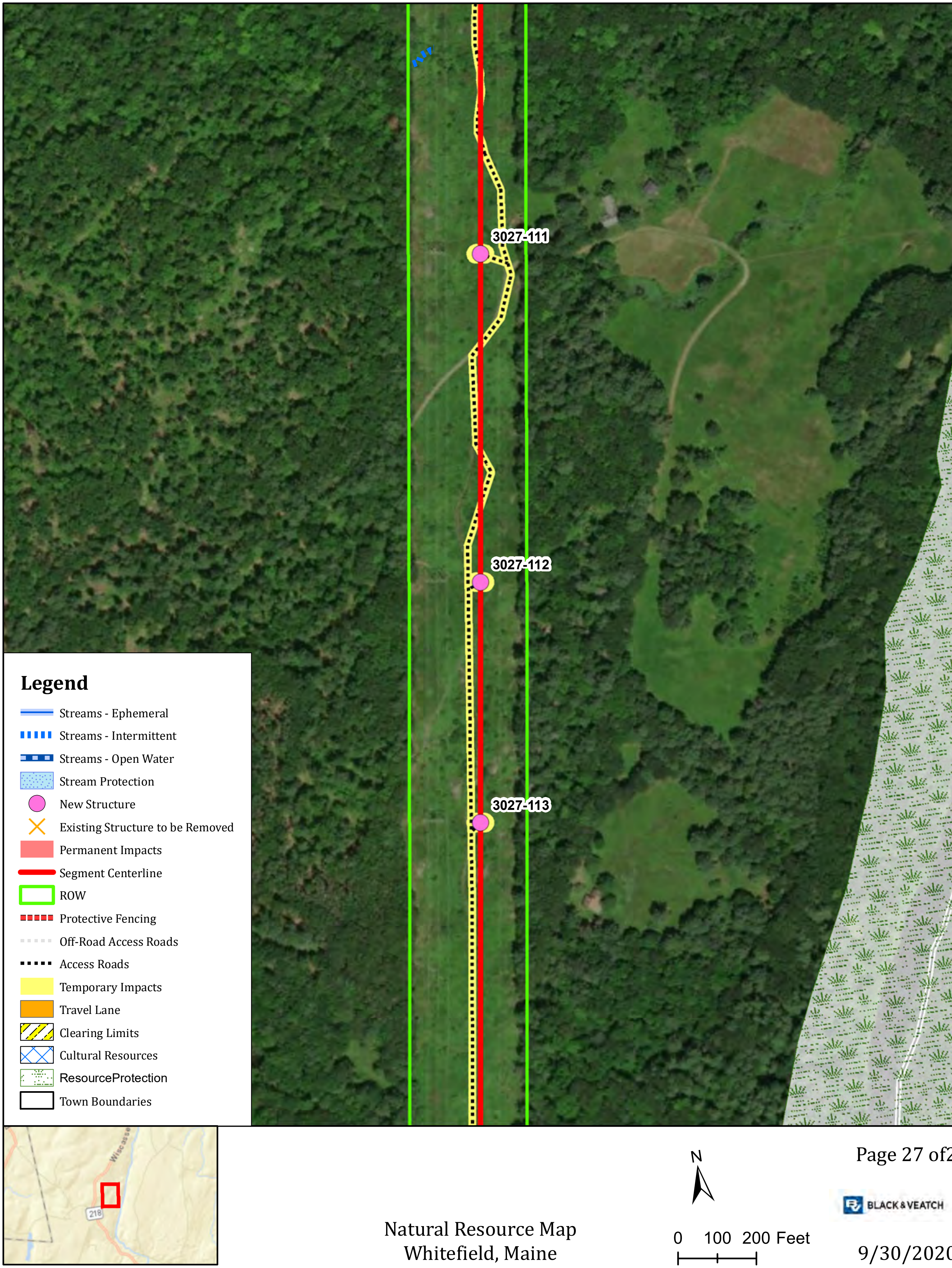
9/30/2020



BLACK & VEATCH

Natural Resource Map
Whitefield, Maine

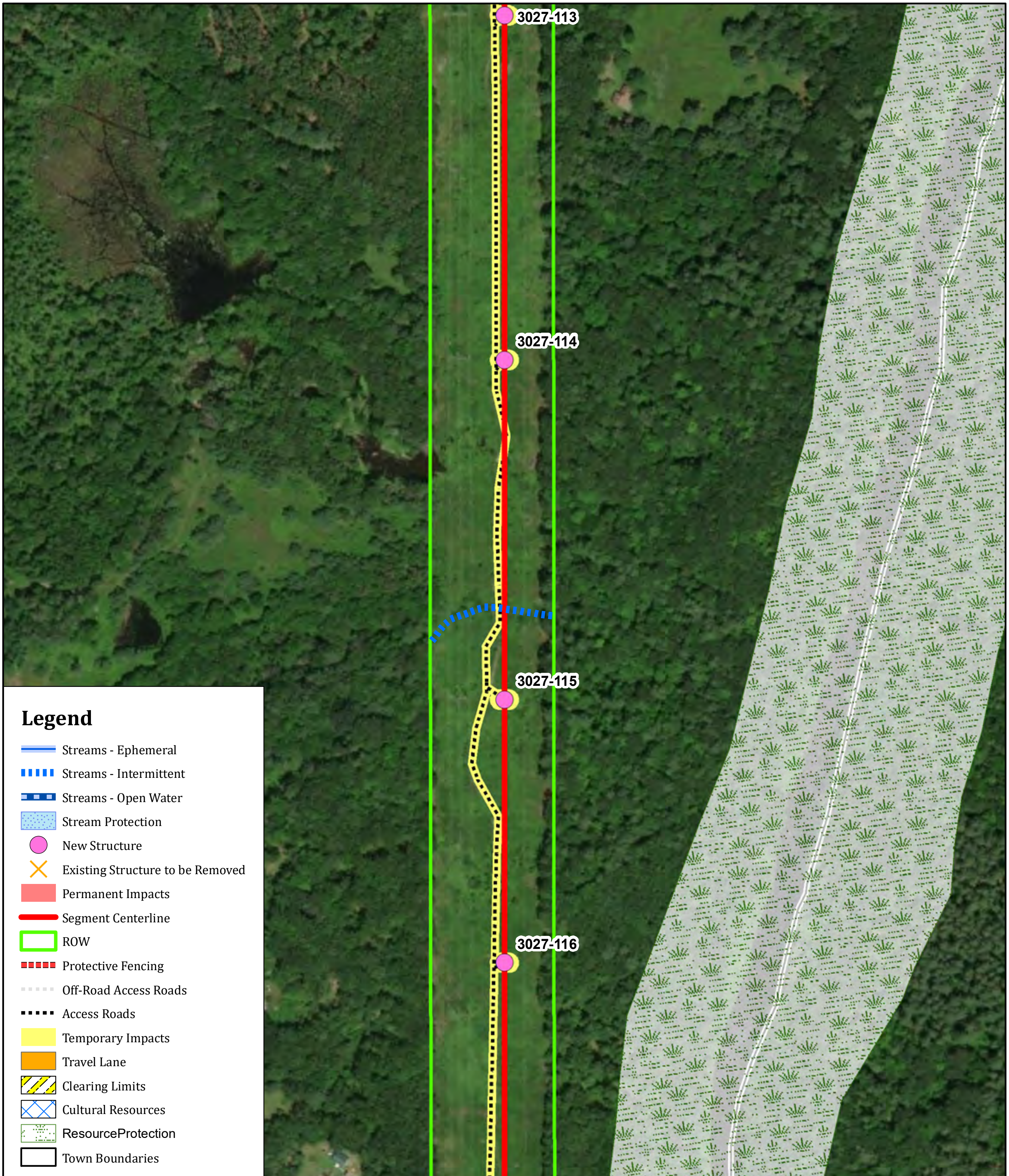
9/30/2020

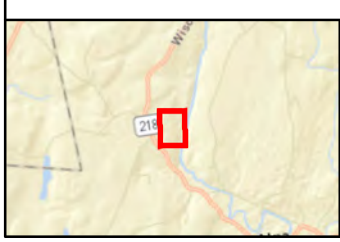


BLACK & VEATCH

Natural Resource Map
Whitefield, Maine

9/30/2020





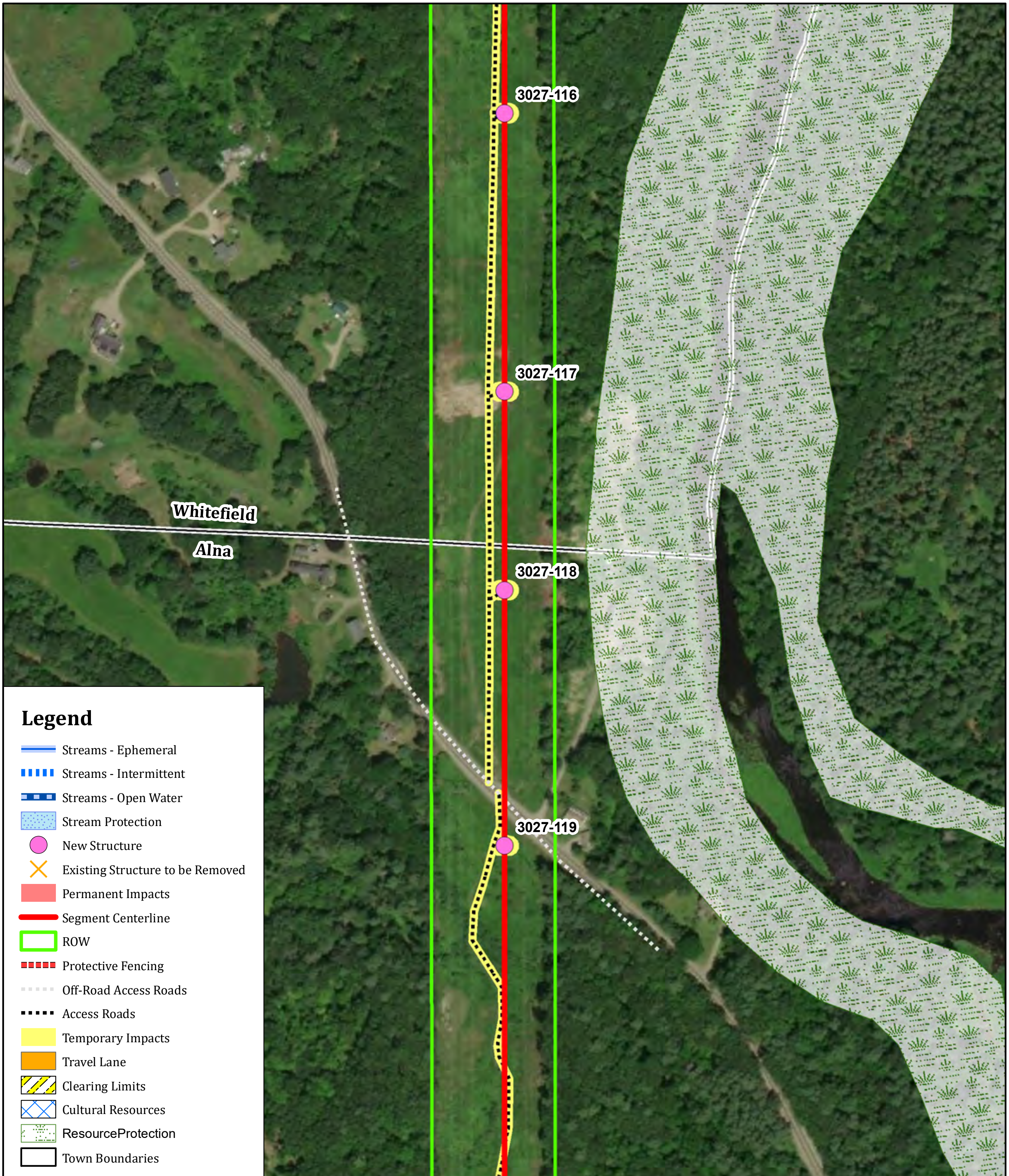
N

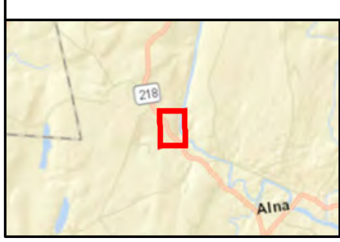
0 100 200 Feet

BLACK & VEATCH

Natural Resource Map
Whitefield, Maine

9/30/2020





Natural Resource Map
Whitefield, Maine

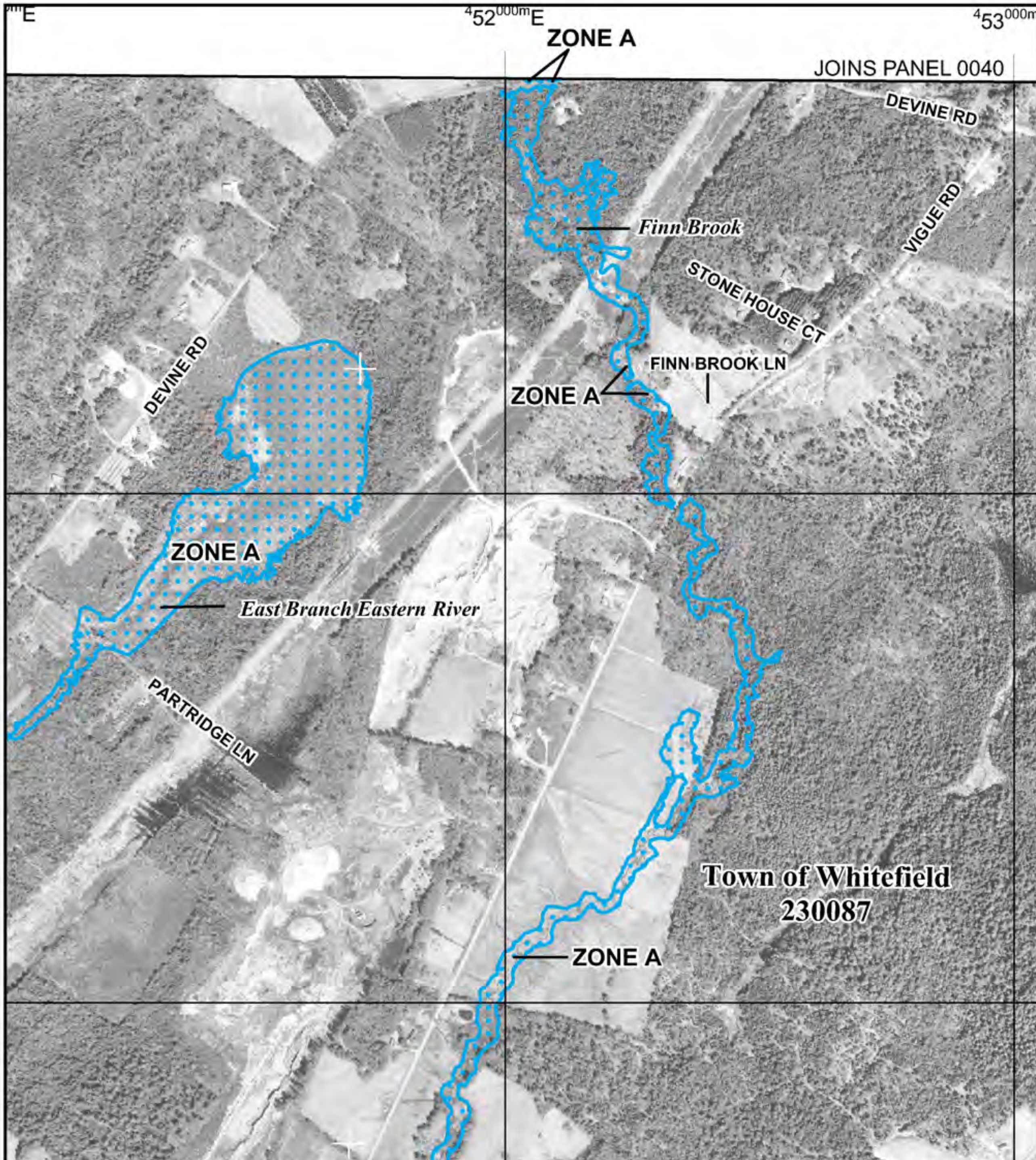
N

0 100 200 Feet

BLACK & VEATCH

9/30/2020

EXHIBIT 1-A FLOODPLAIN AND SOIL SERIES MAPS



MAP SCALE 1" = 1000'

500 0 1000 2000 FEET

METERS

NATIONAL FLOOD INSURANCE PROGRAM

NFIP

PANEL 0130D

FIRM

FLOOD INSURANCE RATE MAP

LINCOLN COUNTY, MAINE

(ALL JURISDICTIONS)

PANEL 130 OF 525

(SEE MAP INDEX FOR FIRM PANEL LAYOUT)

CONTAINS:

COMMUNITY	NUMBER	PANEL	SUFFIX
JEFFERSON, TOWN OF	230085	0130	D
WHITEFIELD, TOWN OF	230087	0130	D

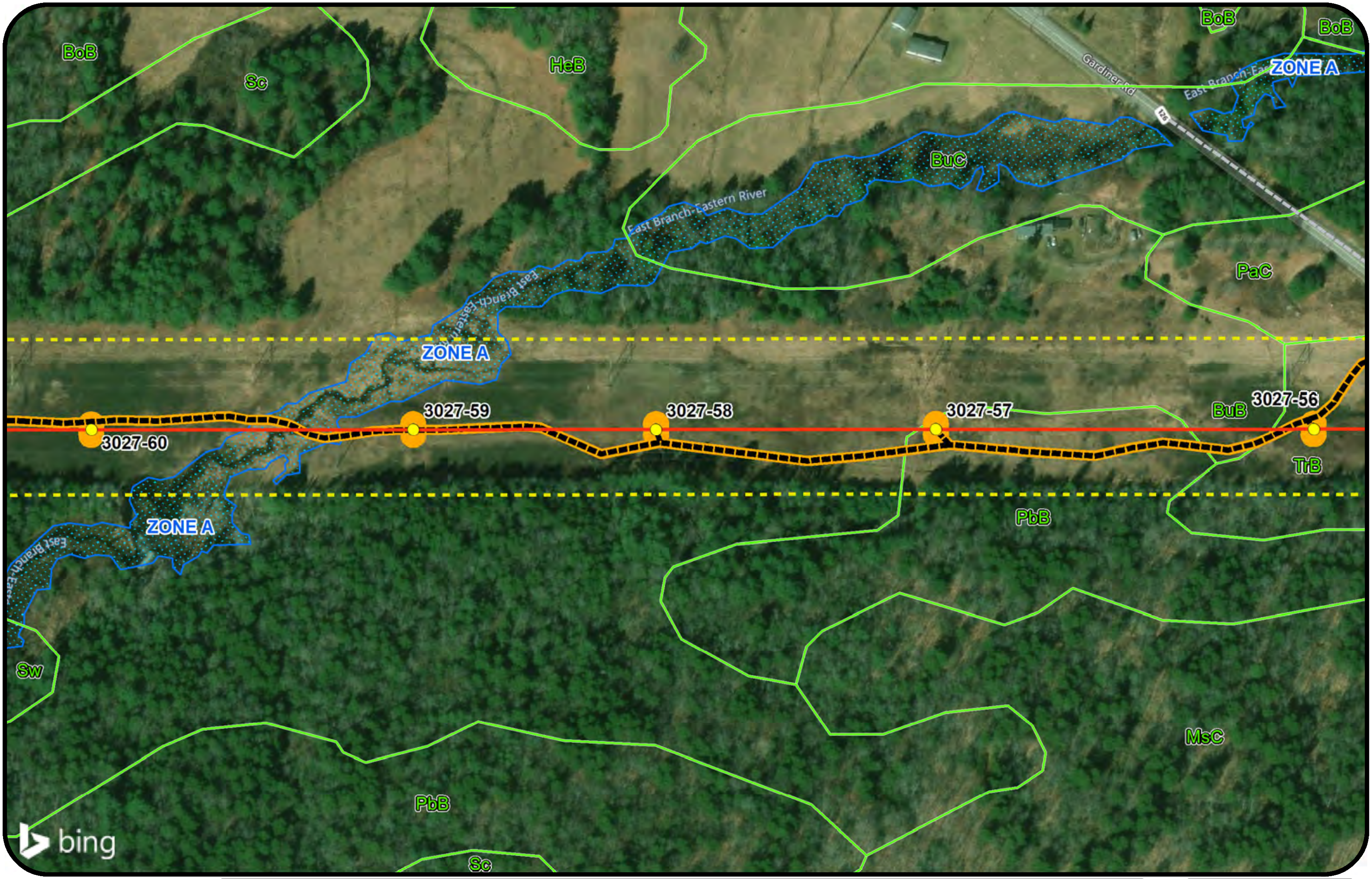
Notice to User: The **Map Number** shown below should be used when placing map orders; the **Community Number** shown above should be used on insurance applications for the subject community.

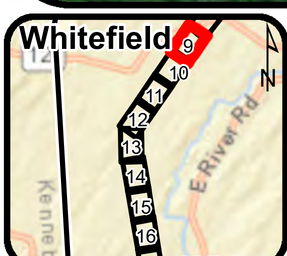
MAP NUMBER
23015C0130D

EFFECTIVE DATE
JULY 16, 2015

Federal Emergency Management Agency

This is an official copy of a portion of the above referenced flood map. It was extracted using F-MIT On-Line. This map does not reflect changes or amendments which may have been made subsequent to the date on the title block. For the latest product information about National Flood Insurance Program flood maps check the FEMA Flood Map Store at www.msc.fema.gov





Legend

- New Structure
- Segment 5 New Transmission Line Centerline
- Segment 5 Renamed Transmission Line Centerline
- FEMA FLOOD ZONE AE
  (An area inundated by 1% annual chance flooding, for which BFEs have been determined.)
- FEMA FLOOD ZONE A
  (An area inundated by 1% annual chance flooding, for which no BFEs have been determined.)
- Existing Structure
- USDA SOILS
- ROW
- Off-Road Access Roads
- Access Roads
- Temporary Impacts
- Town Boundary

BLACK & VEATCH
Building a world of difference.

0 250 Feet

New England Clean Energy Connect

Floodplain and Soil Series

Segment 5 - Whitefield, ME

CENTRAL MAINE POWER

JOINS PANEL 0130

505000 FT

MAP SCALE 1" = 1000'

500 0 1000 2000

FEET

METERS

PANEL 0110D

FIRM

FLOOD INSURANCE RATE MAP

LINCOLN COUNTY, MAINE

(ALL JURISDICTIONS)

PANEL 110 OF 525

(SEE MAP INDEX FOR FIRM PANEL LAYOUT)

CONTAINS:

COMMUNITY	NUMBER	PANEL	SUFFIX
WHITEFIELD, TOWN OF	230087	0110	D

Notice to User: The **Map Number** shown below should be used when placing map orders; the **Community Number** shown above should be used on insurance applications for the subject community.

MAP NUMBER
23015C0110D

EFFECTIVE DATE
JULY 16, 2015

Federal Emergency Management Agency

NATIONAL FLOOD INSURANCE PROGRAM

NFIP

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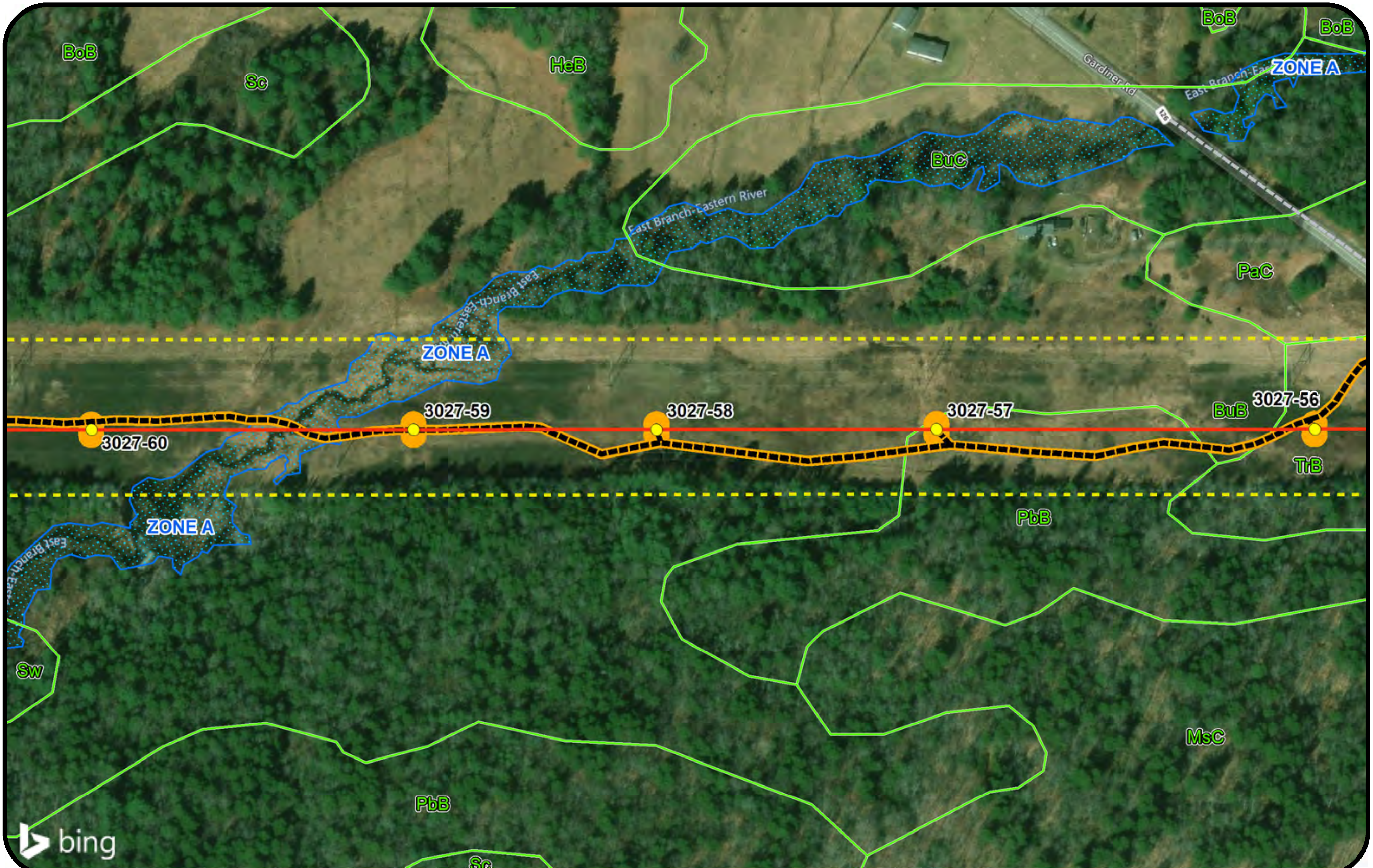

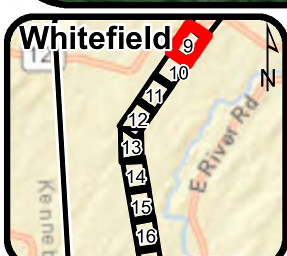

Legend

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- Access Roads
- Temporary Impacts
- Town Boundary

BLACK & VEATCH
Building a world of difference.

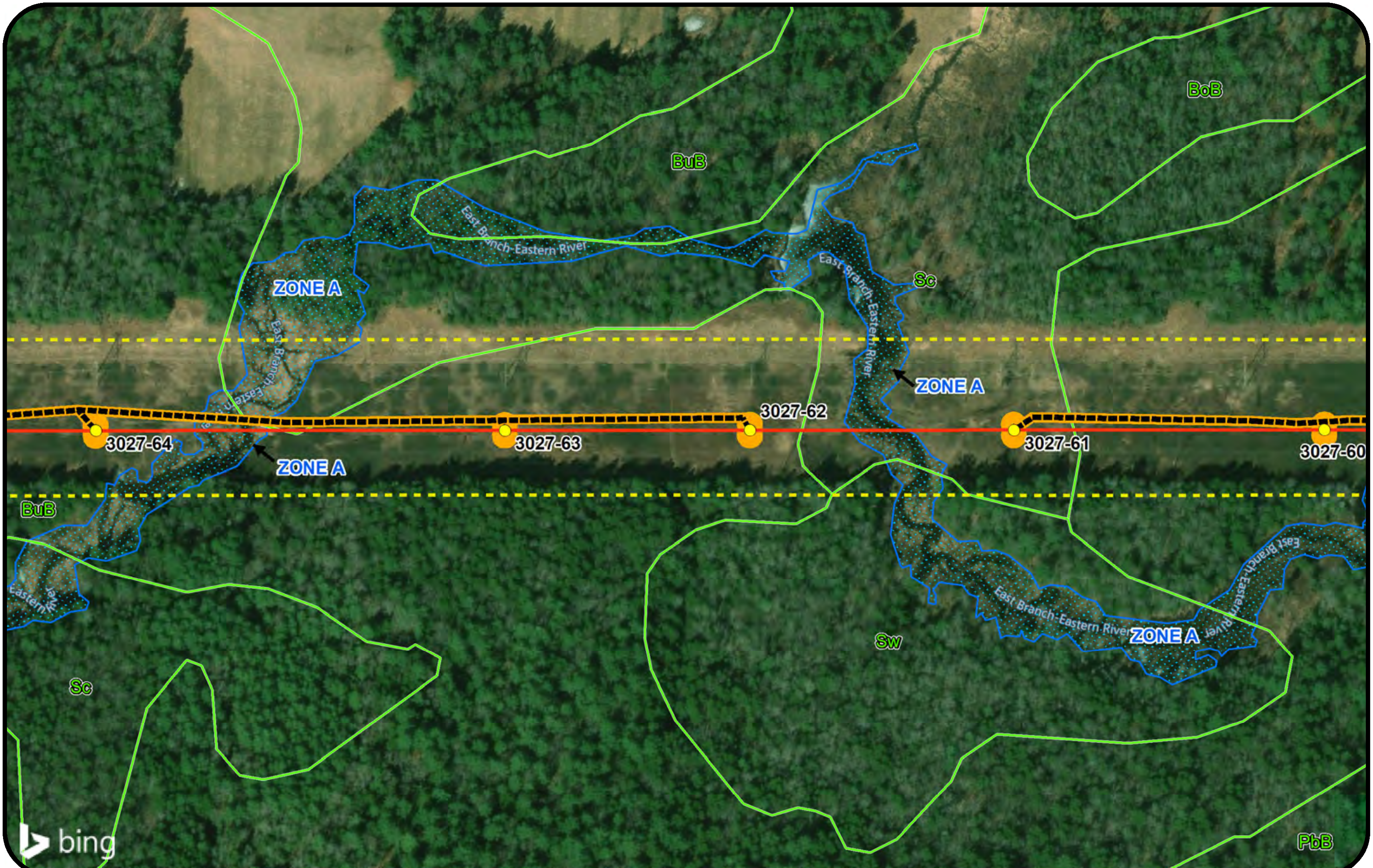
0 250 Feet

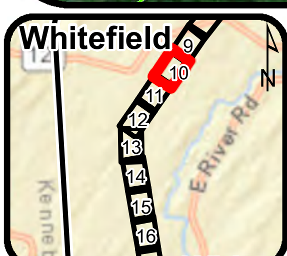
New England Clean Energy Connect

Floodplain and Soil Series

Segment 5 - Whitefield, ME

CENTRAL MAINE POWER





Legend

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- Off-Road Access Roads
- Access Roads
- Temporary Impacts
- Town Boundary

0 250 Feet

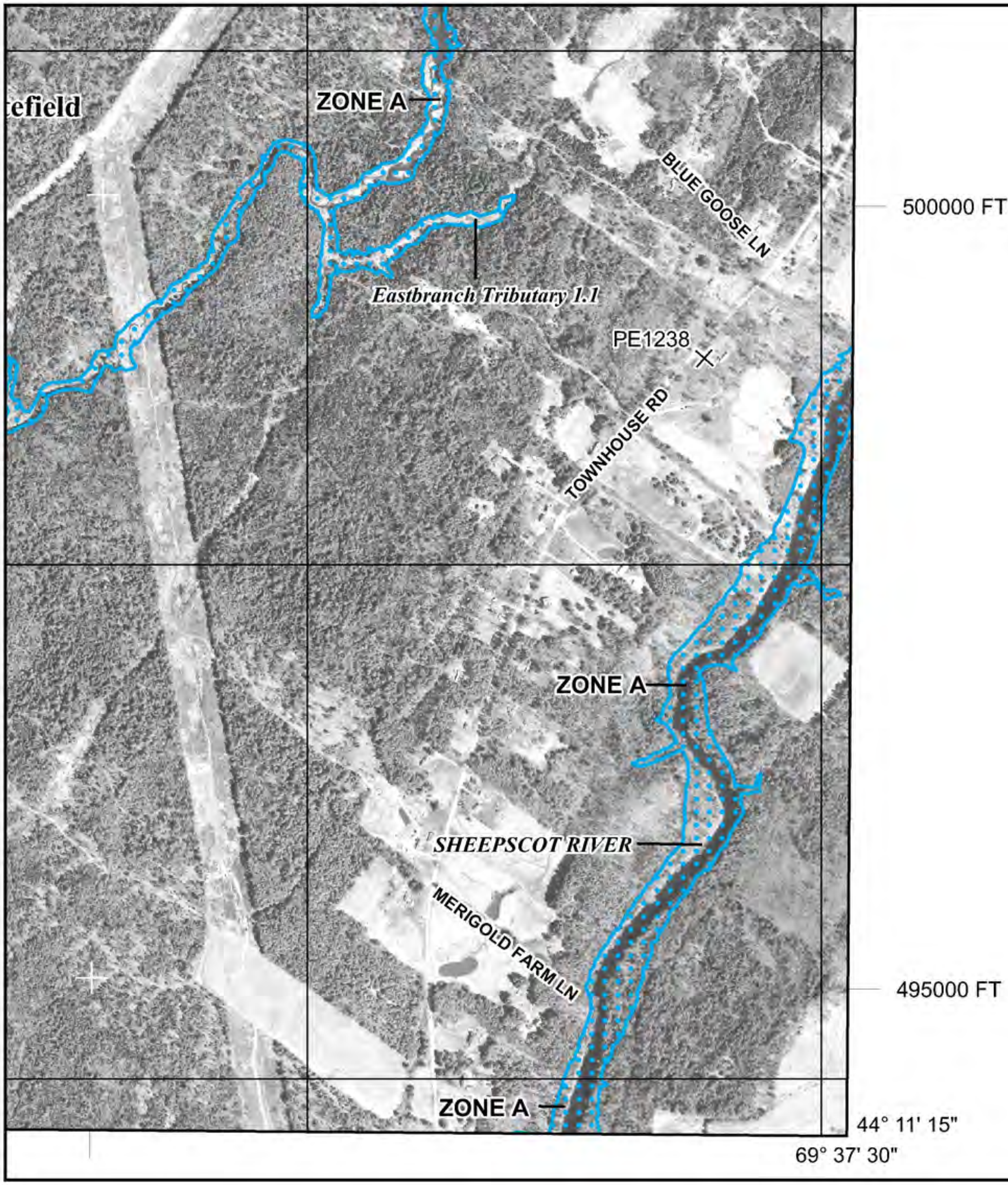
BLACK & VEATCH
Building a world of difference.

New England Clean Energy Connect

Floodplain and Soil Series

Segment 5 - Whitefield, ME

CENTRAL MAINE POWER



MAP SCALE 1" = 1000'

500 0 1000 2000 FEET

METERS

NFIP

NATIONAL FLOOD INSURANCE PROGRAM

PANEL 0110D

FIRM

FLOOD INSURANCE RATE MAP

LINCOLN COUNTY, MAINE

(ALL JURISDICTIONS)

PANEL 110 OF 525

(SEE MAP INDEX FOR FIRM PANEL LAYOUT)

CONTAINS:

COMMUNITY	NUMBER	PANEL	SUFFIX
WHITEFIELD, TOWN OF	230087	0110	D

Notice to User: The **Map Number** shown below should be used when placing map orders; the **Community Number** shown above should be used on insurance applications for the subject community.

MAP NUMBER
23015C0110D

EFFECTIVE DATE
JULY 16, 2015

Federal Emergency Management Agency

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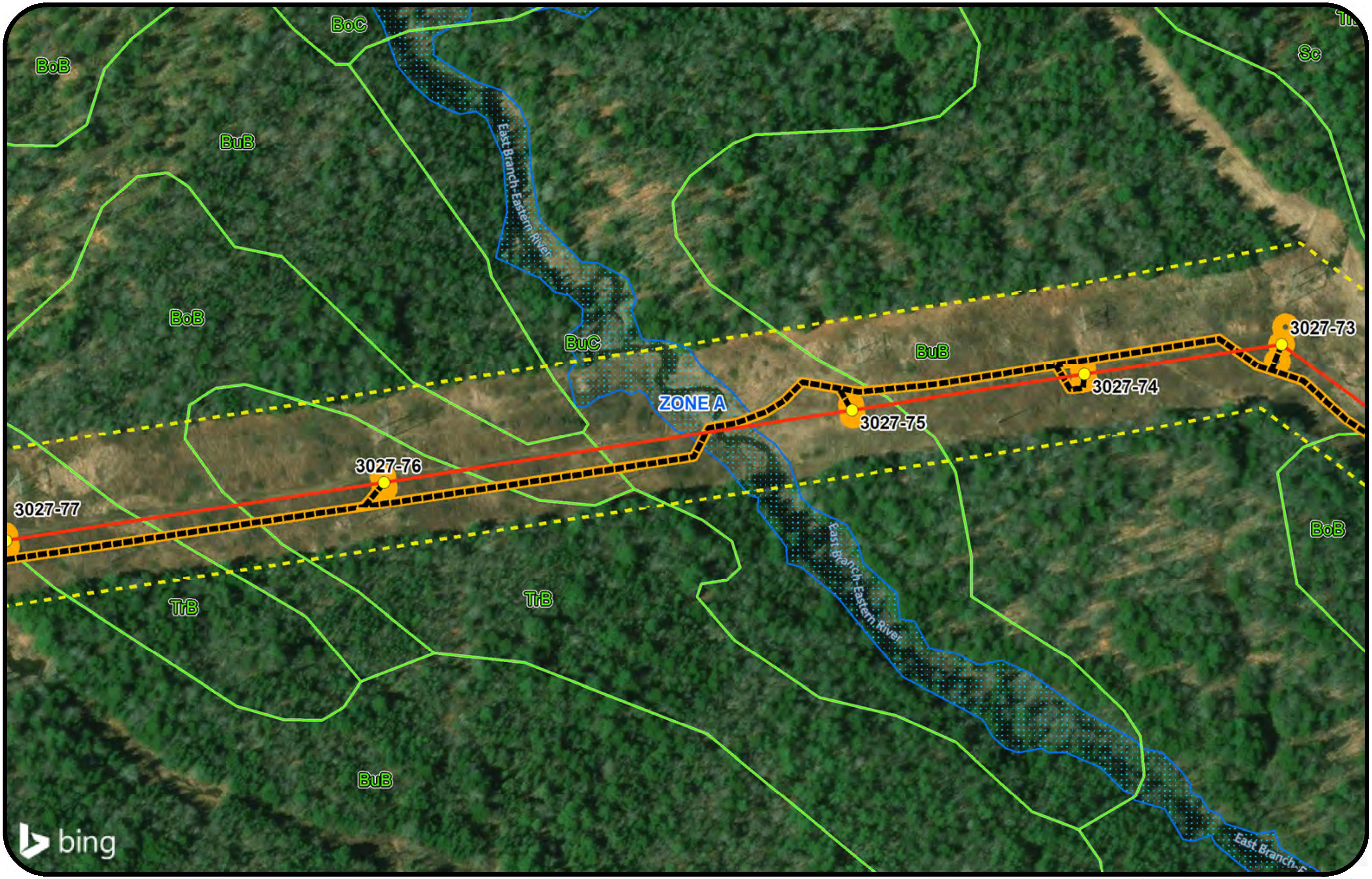

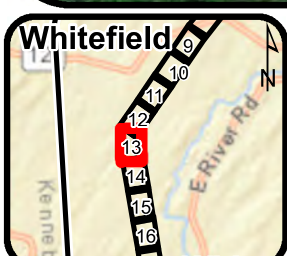

Legend

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- Access Roads
- Temporary Impacts
- Town Boundary

W S N E

0 250 Feet

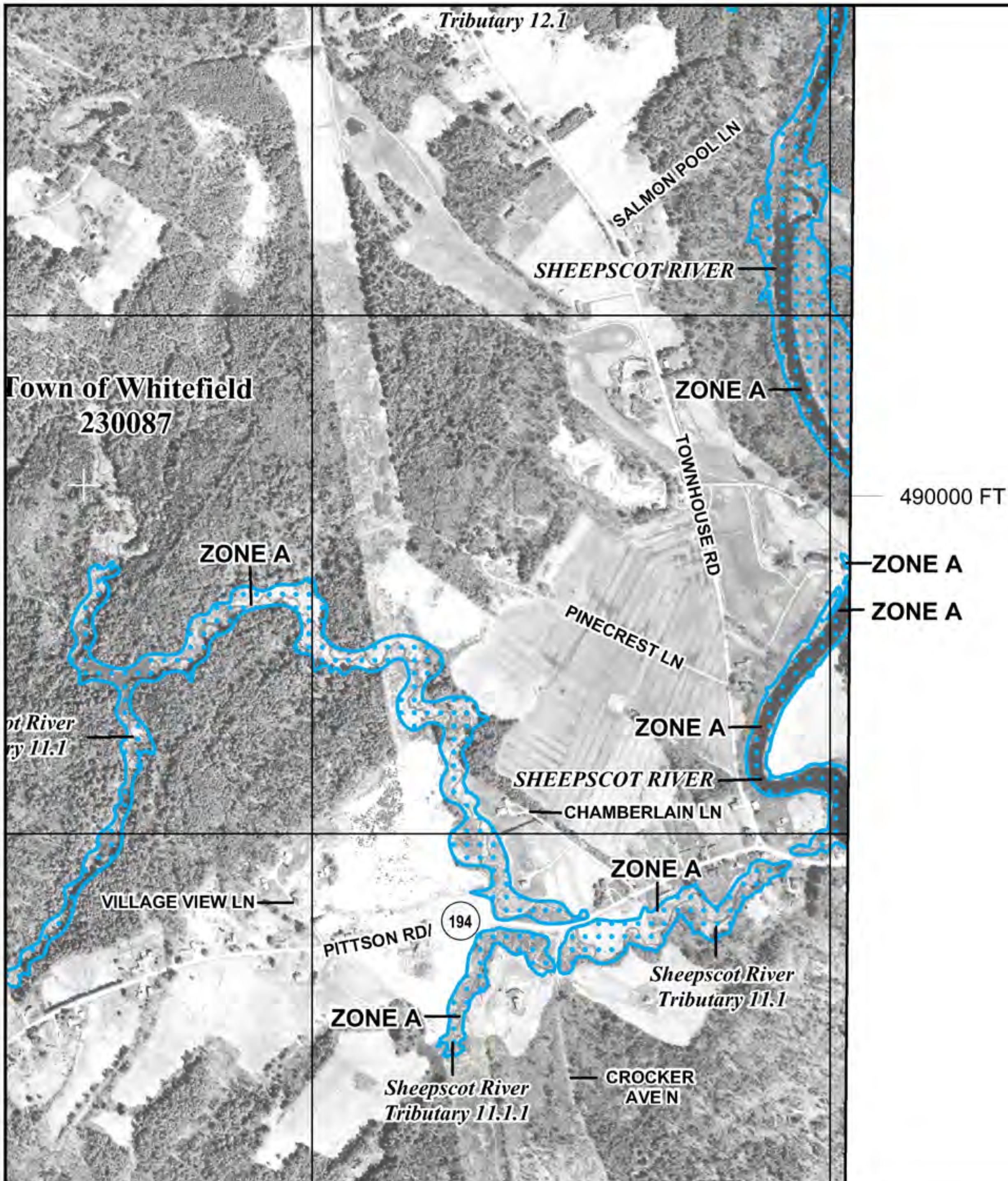
BLACK & VEATCH
Building a world of difference.

New England Clean Energy Connect

Floodplain and Soil Series

Segment 5 - Whitefield, ME

CENTRAL MAINE POWER



MAP SCALE 1" = 1000'

500 0 1000 2000 FEET

METERS

NATIONAL FLOOD INSURANCE PROGRAM

NFIP

PANEL 0120D

FIRM

FLOOD INSURANCE RATE MAP

LINCOLN COUNTY, MAINE

(ALL JURISDICTIONS)

PANEL 120 OF 525

(SEE MAP INDEX FOR FIRM PANEL LAYOUT)

CONTAINS:

COMMUNITY	NUMBER	PANEL	SUFFIX
ALNA, TOWN OF	230083	0120	D
DRESDEN, TOWN OF	230084	0120	D
WHITEFIELD, TOWN OF	230087	0120	D

Notice to User: The **Map Number** shown below should be used when placing map orders; the **Community Number** shown above should be used on insurance applications for the subject community.

MAP NUMBER
23015C0120D

EFFECTIVE DATE
JULY 16, 2015

Federal Emergency Management Agency

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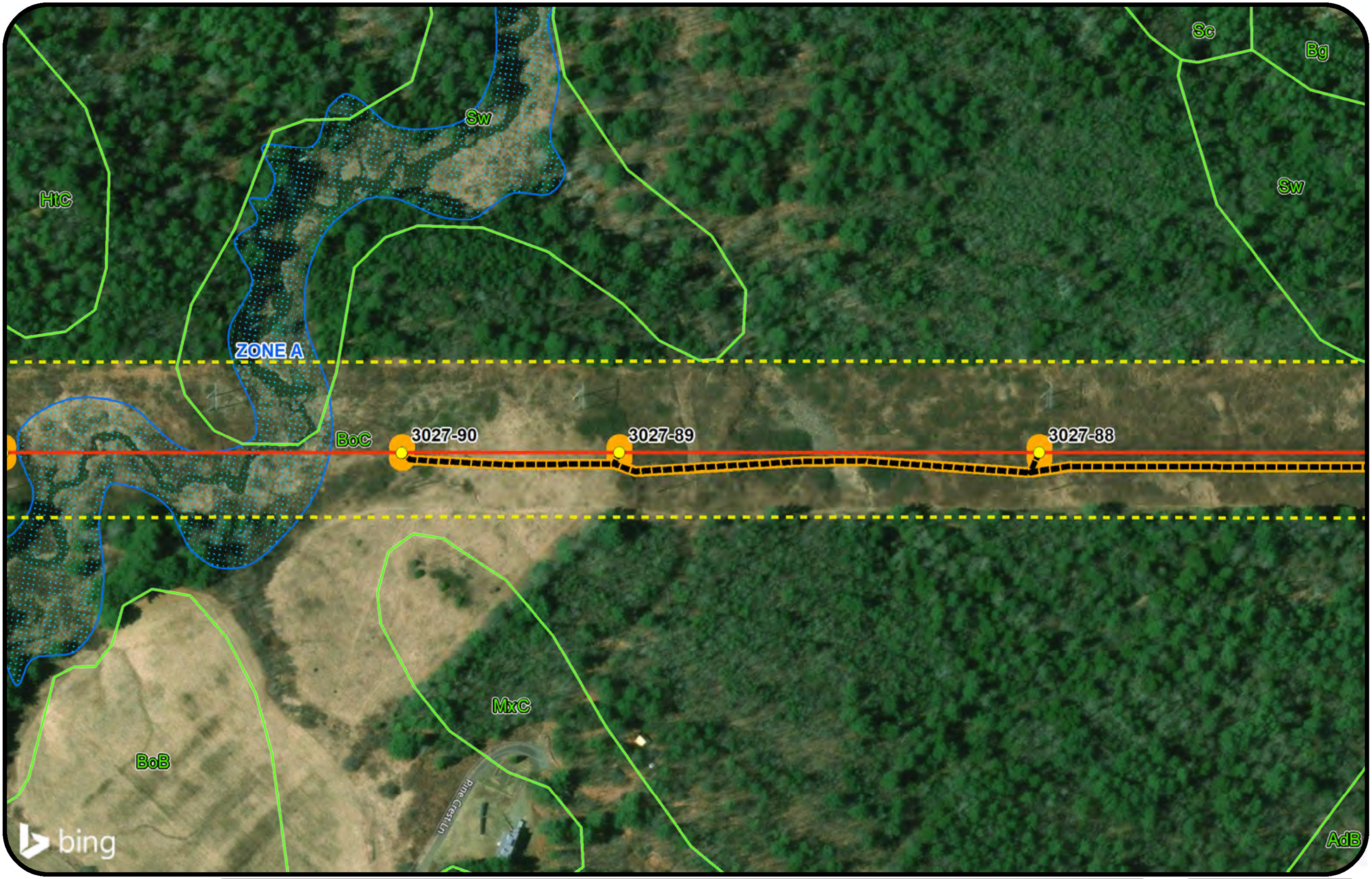

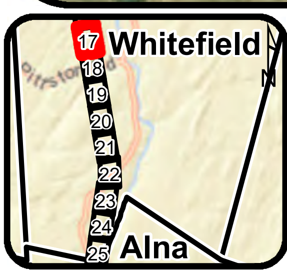

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BLACK & VEATCH
Building a world of difference.

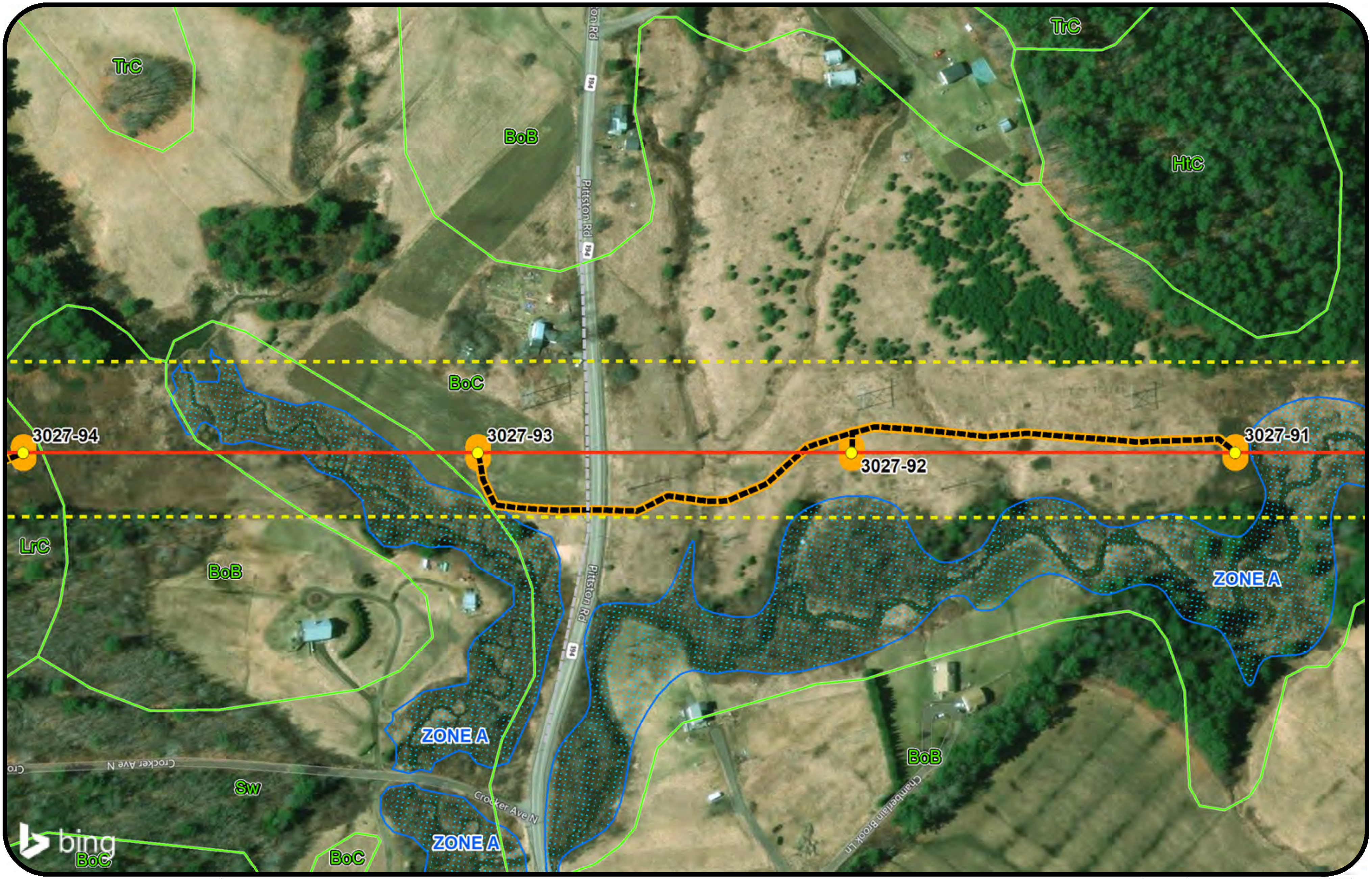
0 250 Feet

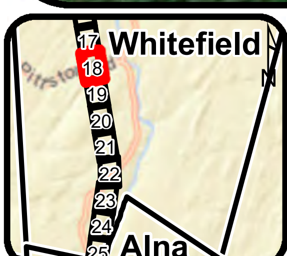
New England Clean Energy Connect

Floodplain and Soil Series

Segment 5 - Whitefield, ME

CENTRAL MAINE POWER





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BLACK & VEATCH
Building a world of difference.

0 250 Feet

New England Clean Energy Connect

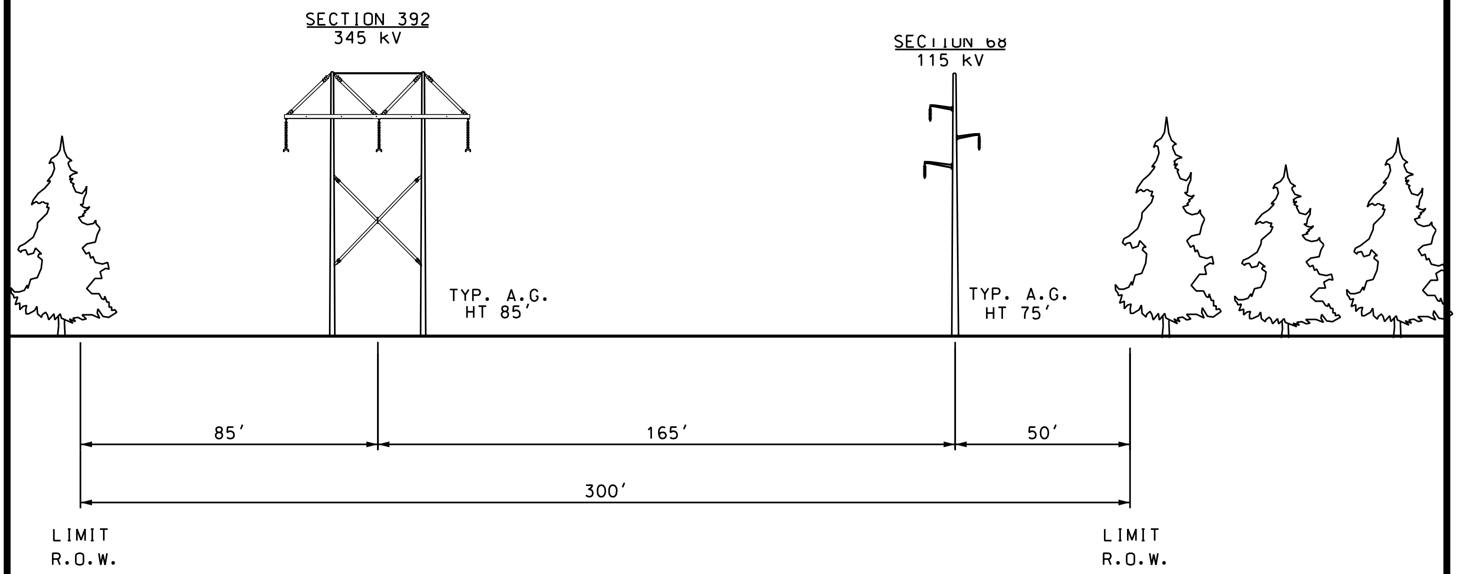
Floodplain and Soil Series

Segment 5 - Whitefield, ME

CENTRAL MAINE POWER

EXHIBIT 2 TRANSMISSION LINE CONFIGURATION CROSS SECTIONS

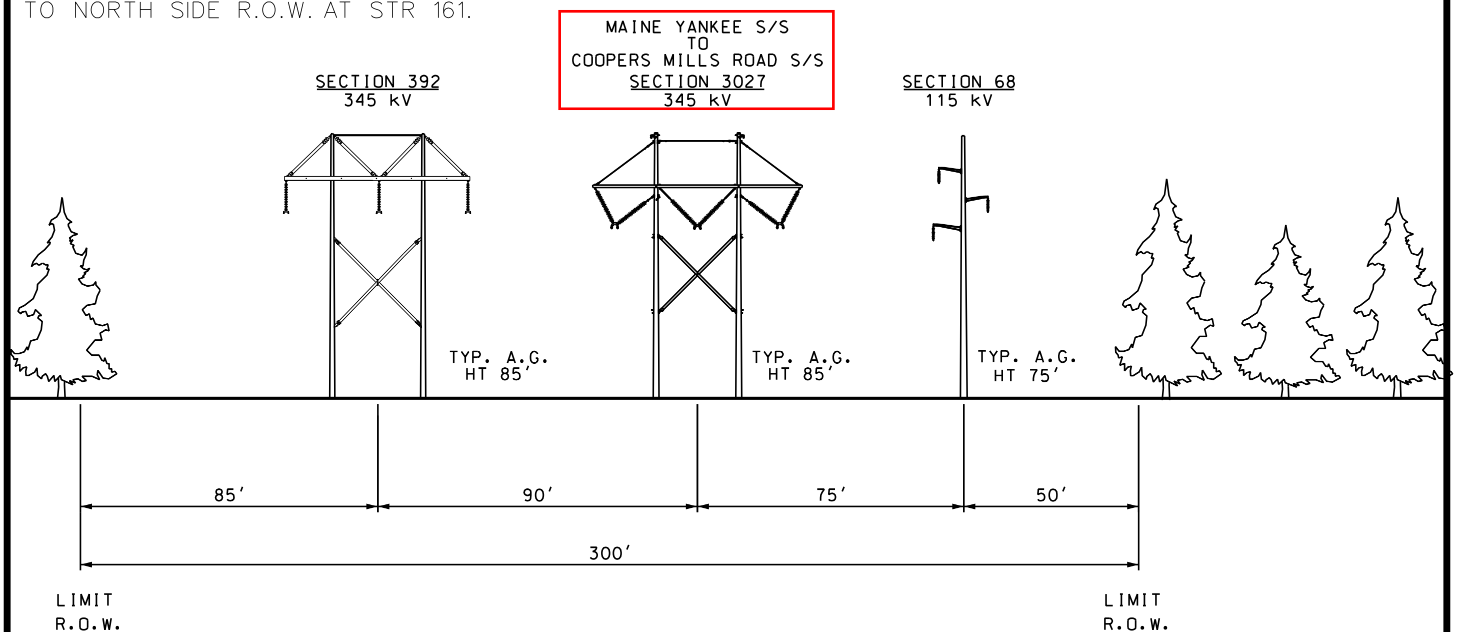
EXISTING



LOOKING FROM MAINE YANKEE S/S TOWARDS COOPERS MILLS ROAD S/S
(APPROX. 17.2 MILES)

NOTE:
EXISTING GAS PIPELINE FROM STR 153 TO STR 210 NORTH SIDE R.O.W., PIPELINE CROSSES TO SOUTH SIDE R.O.W. AT STR 160, CROSSES BACK TO NORTH SIDE R.O.W. AT STR 161.

PROPOSED



LOOKING FROM MAINE YANKEE S/S TOWARDS COOPERS MILLS ROAD S/S
(APPROX. 17.2 MILES)

THIS DRAWING SHALL BE REVISED ON THE CADD SYSTEM ONLY

SECTION 392	POLE 64 TO 214	STA. 434+35 TO 1342+37

EXISTING AND PROPOSED R.O.W.
SEGMENT 5

ENG. CONTRACTOR

NO.	REVISION	DATE	BY
		/ /	
		/ /	
		/ /	
		/ /	
		/ /	
1	ISSUED FOR RFP RESPONSE	9/19/17	PEI

CHECKED		DESIGNED	CRM	DATE	4/10/17
CRM	4/11/17	DRAWN	SCF	APPR.	
SCALE	NTS	CENTRAL MAINE POWER			

SEGMENT 5

SHEET S5-9

EXHIBIT 3 PROOF OF TITLE, RIGHT, OR INTEREST

Central Maine Power
Section 3027 Whitefield – Right, Title and Interest

Deed information recorded at the Lincoln County Registry of Deeds addressing Parties, Book, Page, Date Parcel ID # and Acquisition Type (Easement /Fee) is summarized in the following table.
This information has previously been submitted as demonstration of Right, Title, and Interest to obtain approval of Segment 5 from the Maine Department of Environmental Protection.

Section	Grantor Name	Grantee	Town	County	Deed Book	Deed Page	Deed Date	Box-Env-Doc	Parcel ID #	Acquisition Type
392	Ralph P. Atwater Et Al	CMP	Whitefield	Lincoln	662	78	10/24/1969		54	Fee
392	Arthur R. Elbthel Et Al	CMP	Whitefield	Lincoln	665	93	12/6/1969		55	Fee
392	John W. Cryus Et Al	CMP	Whitefield	Lincoln	662	84	10/24/1969		56	Fee
392	Gertrude Marion Helson	CMP	Whitefield	Lincoln	662	88	10/24/1969		57	Fee
392	Norman A. Nilsen Et Al	CMP	Whitefield	Lincoln	662	50	10/18/1969		58	Fee
392	U.S. Gypsum Company	CMP	Whitefield	Lincoln	734	280	10/29/1969		59	Fee
392	Robert L. Estey Et Al	CMP	Whitefield	Lincoln	662	123	11/8/1969		60	Fee
392	Richard S. Curewitz Et Al	CMP	Whitefield	Lincoln	665	101	12/9/1969		61	Fee
392	Lenoard Kelley Et Al	CMP	Whitefield	Lincoln	662	130	11/3/1969		62	Fee
392	Charles DiPrizio & Sons INC	CMP	Whitefield	Lincoln	665	103	12/12/1969		63	Fee
392	Scott D. Kittredge Et Al	CMP	Whitefield	Lincoln	661	136	9/4/1969		64	Fee
392	Verdon R. Chase	CMP	Whitefield	Lincoln	661	126	9/22/1969		65	Fee
392	John L. Dancer	CMP	Whitefield	Lincoln	661	91	9/15/1969		66	Fee
392	Warren E. Russell Et Al	CMP	Whitefield	Lincoln	661	97	9/16/1969		67	Fee

Section	Grantor Name	Grantee	Town	County	Deed Book	Deed Page	Deed Date	Box-Env-Doc	Parcel ID #	Acquisition Type
392	Bertha Rogers	CMP	Whitefield	Lincoln	656	427	8/14/1969		68	Fee
392	Bertha Rogers	CMP	Whitefield	Lincoln	656	427	8/14/1969		69	Fee
392	John L. Dancer	CMP	Whitefield	Lincoln	661	91	9/15/1969		70	Fee
392	Robert J. Hanna Et Al	CMP	Whitefield	Lincoln	661	130	9/13/1969		71	Fee
392	Francis Burk	CMP	Whitefield	Lincoln	661	122	9/23/1969		72	Fee
392	Robert J. Hanna Et Al	CMP	Whitefield	Lincoln	661	130	9/13/1969		73	Fee
392	G. William Hall Et Al	CMP	Whitefield	Lincoln	656	423	8/14/1969		74	Fee
392	Annie M. Tyler	CMP	Whitefield	Lincoln	661	101	8/16/1969		75	Fee
392	G. William Hall Et Al	CMP	Whitefield	Lincoln	656	423	8/14/1969		76	Fee
392	Annie M. Tyler	CMP	Whitefield	Lincoln	661	101	8/16/1969		77	Fee
392	Wahego Enterprises	CMP	Whitefield	Lincoln	661	61	9/5/1969		78	Fee
392	Michael Saretzky Et Al	CMP	Whitefield	Lincoln	661	58	9/8/1969		79	Fee
392	Donald Tibbetts	CMP	Whitefield	Lincoln	661	165	10/2/1969		80	Fee
392	Laimonis E. Rieksts Et Al	CMP	Whitefield	Lincoln	660	166	8/18/1968		81	Fee
392	A. Loyd Merigold Et Al	CMP	Whitefield	Lincoln	661	56	8/8/1969		82	Fee
392	Polahij Ponomarenko Tarasenko	CMP	Whitefield	Lincoln	662	261	11/28/1969		83	Fee
392	Edmond C. Binns	CMP	Whitefield	Lincoln	661	156	9/30/1969		84	Fee
392	Edmond C. Binns	CMP	Whitefield	Lincoln	670	98	9/8/1970		84.1	Guying Easement
392	Curtis T. Commbs	CMP	Whitefield	Lincoln	661	128	9/24/1969		85	Fee
392	George H. Carter Et Al	CMP	Whitefield	Lincoln	661	124	9/22/1969		86	Fee
392	Roy W. Ripley	CMP	Whitefield	Lincoln	662	90	10/29/1969		87	Fee
392	Mary Anne Kelley	CMP	Whitefield	Lincoln	656	425	8/13/1969		88	Fee
392	Ralph L. Carter	CMP	Whitefield	Lincoln	661	89	9/15/1969		89	Fee
392	Hazel T. Fowie Et Al	CMP	Whitefield	Lincoln	662	44	10/20/1969		90	Fee

Section	Grantor Name	Grantee	Town	County	Deed Book	Deed Page	Deed Date	Box-Env-Doc	Parcel ID #	Acquisition Type
392	Walter H. Forester Et Al	CMP	Whitefield	Lincoln	661	93	9/16/1969		91	Fee
392	Donald Tibbetts	CMP	Whitefield	Lincoln	661	167	10/2/1969		92	Fee
392	Richard L. Weeks Et Al	CMP	Whitefield	Lincoln	662	54	10/21/1969		93	Fee
392	Charles Edward Tibbetts	CMP	Whitefield	Lincoln	662	52	10/21/1969		94	Fee
392	Robert C. Johanson Et Al	CMP	Whitefield	Lincoln	661	134	9/23/1969		95	Fee
392	Paul A. Vigue	CMP	Whitefield	Lincoln	661	169	9/30/1969		96	Fee
392	Edward John Burke Et Al	CMP	Whitefield	Lincoln	665	136	12/29/1969		97	Fee
392	Martha Trainor	CMP	Whitefield	Lincoln	656	432	8/13/1969		98	Fee
392	Cora M. Caron	CMP	Whitefield	Lincoln	657	417	9/8/1969		99	Fee
392	Thomas P. Kapantais Et Al	CMP	Whitefield	Lincoln	655	331	6/16/1969		100	Fee
392	Leo H. Fox	CMP	Whitefield	Lincoln	661	152	9/30/1969		101	Fee
392	Floyd A. Edmonds Et Al	CMP	Whitefield	Lincoln	662	435	12/29/1969		102	Fee
392	John Dysart Et Al	CMP	Whitefield	Lincoln	656	422	8/15/1969		103	Fee
392	George Carlezon	CMP	Whitefield	Lincoln	662	42	10/22/1969		104	Fee
392	Violet H. Richards	CMP	Whitefield	Lincoln	660	164	8/2/1969		105	Fee
392	Herbert A. Muller Jr Et Al	CMP	Whitefield	Lincoln	662	48	10/10/1969		106	Fee
392	Osborn M. Delano Et Al	CMP	Whitefield	Lincoln	661	150	10/1/1969		107	Fee
392	Paul A. Vigue	CMP	Whitefield	Lincoln	661	171	9/30/1969		108	Fee
392	Milan M. Dean	CMP	Whitefield	Lincoln	665	141	12/30/1969		109	Fee

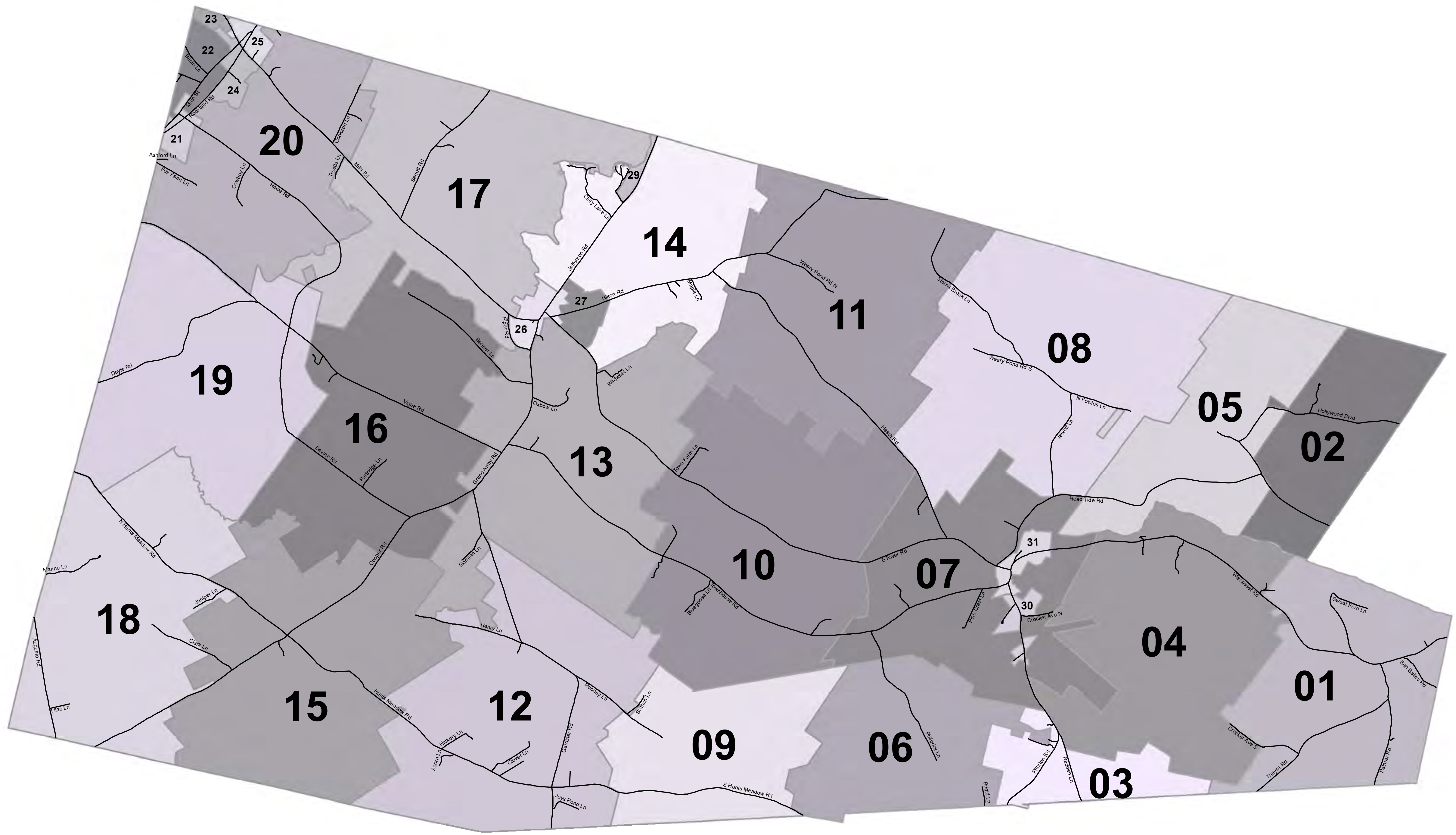
Section	Grantor Name	Grantee	Town	County	Deed Book	Deed Page	Deed Date	Box-Env-Doc	Parcel ID #	Acquisition Type
392	Earl L. Glidden	CMP	Whitefield	Lincoln	661	55	9/9/1969		110	Fee
392	John N. Eastman Et Al	CMP	Whitefield	Lincoln	662	46	10/20/1969		111	Fee
392	Harry A. Slefkin Et Al	CMP	Whitefield	Lincoln	666	1	10/15/1969		112	Fee
392	Robert A. Hawksley Et Al	CMP	Whitefield	Lincoln	662	128	11/6/1969		113	Fee
68	Brackett & Shaw Co.	CMP	Whitefield	Lincoln	441	291	4/8/1941	82-3-3	67	Fee
68	John E. Heath	CMP	Whitefield	Lincoln	441	258	4/7/1941	82-8-28	66	Fee
68	Ellisaus B. Nilsen	CMP	Whitefield	Lincoln	441	461	4/15/1941	82-4-5	65	Fee
68	Ida E. Cary	CMP	Whitefield	Lincoln	441	435	4/17/1941	82-3-26	64	Fee
68	Irving B. Arnold	CMP	Whitefield	Lincoln	441	434	4/15/1941	82-3-25	63	Fee
68	Sadie J. Plummer Et Al	CMP	Whitefield	Lincoln	441	444	4/21/1941	82-4-6	62	Fee
68	Carlton E. Ware	CMP	Whitefield	Lincoln	441	464	4/15/1941	82-4-12	61	Fee
68	Carroll A. Potter	CMP	Whitefield	Lincoln	441	445	4/15/1941	82-4-7	60	Fee
68	State of Maine	CMP	Whitefield	Lincoln	441	463	4/29/1941	82-3-21	59	Fee
68	Earle R. Potter	CMP	Whitefield	Lincoln	441	538	4/12/1941	82-4-15	58	Fee
68	Edith H. Wentworth Et Al	CMP	Whitefield	Lincoln	441	539	4/21/1941	82-4-16	57	Fee
68	Grace P. Bailey	CMP	Whitefield	Lincoln	441	309	4/15/1941	82-3-2	56	Fee
68	Warren E. Cunningham	CMP	Whitefield	Lincoln	441	314	3/15/1941	82-3-10	55	Fee
68	Edwin L. Russell	CMP	Whitefield	Lincoln	441	320	4/15/1941	82-3-23	54	Fee
68	William H. Eastman	CMP	Whitefield	Lincoln	441	440	4/18/1941	82-4-1	53	Fee
68	Ira H. Waller	CMP	Whitefield	Lincoln	441	450	4/17/1941	82-4-11 & 18	52	Fee
68	Ernest E. Dunton	CMP	Whitefield	Lincoln	441	438	4/21/1941	82-3-30	51	Fee
68	Harriet J. Hall	CMP	Whitefield	Lincoln	441	316	4/15/1941	82-3-13	50	Fee
68	Annie M. Tyler	CMP	Whitefield	Lincoln	441	449	4/16/1941	82-4-10	49	Fee

Section	Grantor Name	Grantee	Town	County	Deed Book	Deed Page	Deed Date	Box-Env-Doc	Parcel ID #	Acquisition Type
68	Dexter Kensell	CMP	Whitefield	Lincoln	441	301	4/12/1941	82-3-15	48	Fee
68	Peter King	CMP	Whitefield	Lincoln	441	303	4/12/1941	82-3-17	47	Fee
68	Paul King	CMP	Whitefield	Lincoln	441	302	4/12/1941	82-3-16	46	Fee
68	Arthur F. Merigold	CMP	Whitefield	Lincoln	441	318	4/14/1941	82-3-22 & 82-4-20	45	Fee
68	Katherine M. Comeau	CMP	Whitefield	Lincoln	441	312	4/15/1941	82-3-8	44	Fee
68	Percy E Chaney Et Al	CMP	Whitefield	Lincoln	441	310	4/10/1941	82-3-6	43	Fee
68	Bertha M. Chaney	CMP	Whitefield	Lincoln	441	436	4/18/1941	82-3-27	42	Fee
68	Curtis T. Coombs	CMP	Whitefield	Lincoln	441	294	4/11/1941	82-3-9	41	Fee
68	Warren E. Cunningham	CMP	Whitefield	Lincoln	441	295	4/12/1941	82-3-10	40	Fee
68	Charles Ripley Et Al	CMP	Whitefield	Lincoln	441	446	4/16/1941	82-4-8	39	Fee
68	Mary A. Kelley	CMP	Whitefield	Lincoln	441	300	4/11/1941	82-3-19	38	Fee
68	Warren E. Cunningham	CMP	Whitefield	Lincoln	441	457	4/15/1941	82-3-29	37	Fee
68	George A. Jackson	CMP	Whitefield	Lincoln	441	298	4/12/1941	82-3-14 & 29	37	Fee
68	Clyde S. Fowle	CMP	Whitefield	Lincoln	441	296	4/10/1941	82-3-12	36	Fee
68	John F. Goodwin	CMP	Whitefield	Lincoln	441	441	4/18/1941	82-4-2	35	Fee
68	Arthur J. Jean	CMP	Whitefield	Lincoln	441	442	4/22/1941	82-4-3	34	Fee
68	Charles Tibbetts	CMP	Whitefield	Lincoln	441	448	4/23/1941	82-4-9	32	Fee
68	Mary O'Brien	CMP	Whitefield	Lincoln	433	435	5/17/1941	82-4-17	33	Fee
68	John Kelley	CMP	Whitefield	Lincoln	441	299	4/10/1941	82-3-18	33	Fee
68	Arthur K. Chisam	CMP	Whitefield	Lincoln	441	437	4/16/1941	82-3-28	31	Fee
68	Leonard M. Brann	CMP	Whitefield	Lincoln	441	292	4/11/1941	82-3-4	30	Fee
68	Edward B. Kinsella	CMP	Whitefield	Lincoln	441	460	4/28/1941	82-4-4	29	Fee
68	Augustus LeClair	CMP	Whitefield	Lincoln	441	533	4/14/1941	82-3-20	28	Fee
68	Town of Whitefield	CMP	Whitefield	Lincoln	441	266	4/5/1941	82-3-24	27	Fee
68	Fox. Thomas M. Fox. Thomas M.	CMP	Whitefield	Lincoln	441	537	5/2/1941	82-2-14	26	Fee

Section	Grantor Name	Grantee	Town	County	Deed Book	Deed Page	Deed Date	Box-Env-Doc	Parcel ID #	Acquisition Type
68	Peter Field	CMP	Whitefield	Lincoln	441	257	4/3/1941	82-3-27	25	Fee
68	John M. Devine	CMP	Whitefield	Lincoln	444	144	4/14/1941	82-2-11	24	Fee
68	Mary E. Burns Et Al	CMP	Whitefield	Lincoln	441	293	4/11/1941	82-3-5	23	Fee
68	State of Maine	CMP	Whitefield	Lincoln	441	264	4/3/1941	82-3-21	22	Fee
68	Peter Storkson	CMP	Whitefield	Lincoln	441	265	4/3/1941	82-2-33	21	Fee
68	James E. Keating	CMP	Whitefield	Lincoln	441	234	3/20/1941		19	Fee
68	Mary E Hanley	CMP	Whitefield	Lincoln	445	62	3/18/1942	82-4-21 & 22	20	Fee
68	Osborn M. Delano Et Al	CMP	Whitefield	Lincoln	1900	172	7/28/1993	68-19	19-1	Fee
68	Theodore Chisam	CMP	Whitefield	Lincoln	441	231	3/26/1941	82-2-2	18	Fee
68	Maurice L. Reilly	CMP	Whitefield	Lincoln	441	139	3/6/1941	82-2-5	17	Fee
68	Earl L. Glidden	CMP	Whitefield	Lincoln	441	146	3/7/1941	82-2-1	16	Fee
68	John M. Eastman	CMP	Whitefield	Lincoln	441	145	3/10/1941	82-1-30	15	Fee
68	Alexander Sayer	CMP	Whitefield	Lincoln	441	140	3/6/1941	82-2-6	14	Fee

EXHIBIT 4 LIST OF ABUTTERS

Section 3027 - Whitefield Abutters Within 500'						
Map-Lot	Owner (1st Owner, Full Name)	Owner 2 (2nd+ Owner(s), Full Name)	Mailing Address	Mailing Town	Mailing State	Mailing ZIP
009-015	Alan and Melissa Thornton		16 Henry Lane	Whitefield	ME	04353
019-012-B	Alicia and Timothy Huff		366 Devine Road	Whitefield	ME	04353
004-006-A	Andrew Miner		503 Wiscasset Road	Whitefield	ME	04353
019-050-A	Anita Newell		PO Box 361	Coopers Mills	ME	04341
004-004, 004-008, 004-009	Ann E. Weiss Living Trust	c/o Ann E. Weiss, Trustee	403 Wiscasset Road	Whitefield	ME	04353
019-028	Arthur and Nancy Peters		239 Doyle Road	Whitefield	ME	04353
019-038, 019-038-001	Barbara S. Vanderbilt &	Richard Curewitz	85 Doyle Road	Whitefield	ME	04353
012-054, 012-057, 013-003, 013-004, 013-011, 007-029, 009-027	Barry and Elaine Tibbetts		61 Townhouse Road	Whitefield	ME	04353
007-024	Brigid Gibson-Griffin		34 Philbrick Lane	Whitefield	ME	04353
004-003	Bryant and Candace Lewis		420 Wiscasset Road	Whitefield	ME	04353
010-001	Byron and Kathleen Kelch		493 West River Road	Palatka	FL	32177
001-046	Catherine Cyrus	c/o Holly C. Zeeb, Trustee	36 Longfellow Avenue	Brunswick	ME	04011
016-040-C	Christopher Monroe		42 Stone House Court	Whitefield	ME	04353
009-021	Conrad and Stephanie Pomerleau		282 South Hunts Meadow Road	Whitefield	ME	04353
016-021	David and Holly Cote		P.O. Box 17	Whitefield	ME	04353
004-002-A, 004-001-A	David Hardman		10 Nilsen Lane	Whitefield	ME	04353
009-014. 010-013, 012-060, 013-001	David M. and Theresa Magnusen		23 Rooney Lane	Whitefield	ME	04353
013-018	Dean Pepper		269 Young Road	Fayette	ME	04349
013-025	Deanne Crocker		P.O. Box 98	Whitefield	ME	04353
009-032, 010-005	Dennis R and Janet Binns		509 Townhouse Road	Whitefield	ME	04353
012-049	Domenick Montagnino		170 School Street, Apt 1B	Unity	ME	04988
006-010, 007-025	Donald D. and Lois G. Morey, Trustees		5 Philbrick Lane	Whitefield	ME	04353
001-058-A	Donna J. Wallace		2271 Alna Road	Alna	ME	04535
012-049-A	Douglas A. and Evelyn A. Kinney		102 Duncan Road	Jefferson	ME	04348
030-012-A, 030-016	Douglas and Elizabeth Brown		63 Pittston Road	Whitefield	ME	04353
013-026-A	Duane Mason		43 Gardiner Road	Whitefield	ME	04353
001-043, 001-044	Dwight A. & Cynthia Oakes		488 Wiscasset Road	Whitefield	ME	04353
010-010	Edward Hall		301 Briarwood Lane	New Bern	NC	28560
009-020	Emery P. Smith &	Cynthia St. Peter	244 South Hunts Meadow Road	Whitefield	ME	04353
001-006-A	Erin Stodder		489 Wiscasset Road	Whitefield	ME	04353
004-041	Eugene W. And James W. Kelley		226 Atlantic Avenue	Boothbay Harbor	ME	04538
009-019	Franklin Ober		172 Rooney Lane	Whitefield	ME	04353
001-059	Gail C. and Hallis A. Thayer		778 Wiscasset Road	Whitefield	ME	04353
007-018-F	George and Mary Ann Hall		822 Townhouse Road	Whitefield	ME	04353
006-008, 006-011-B	George Hall, Jr.		822 Townhouse Road	Whitefield	ME	04353
007-012	George W. Hall, Jr. &	Harold Piacopolos	822 Townhouse Road	Whitefield	ME	04353
019-050	Gladys Solomon Heirs	c/o Michael Solomon	15 Teddy Bear Lane	Augusta	ME	04330
004-038	Greg Cederlund		28 Trails End	Freeport	ME	04032
001-053, 001-054	Gregory D. and Daryl Hodgkins &	Cheryl Sawyer	645 Wiscasset Road	Whitefield	ME	04353
007-009	Gregory M. and Lisa J. Hart		11 Crocker Avenue North	Whitefield	ME	04353
001-058-E	Hallis A. Thayer, II		7 Petticoat Acres Lane	Whitefield	ME	04353
007-014, 030-011	Hellen Dancer		P.O. Box 234	Whitefield	ME	04353
019-042	Imelda Yorkus		594 Vigue Road	Whitefield	ME	04353
013-020	James and Ann Silin		17 Gorman Lane	Whitefield	ME	04353
012-047-A	James R. Barnard		P.O. Box 18	Whitefield	ME	04353
016-014-A	Jane A. Russo		217 Devine Road	Whitefield	ME	04353
019-039-B	Jane O'Mahoney &	Maureen O'Connor	51 Doyle Road	Whitefield	ME	04353
007-025-A	Jason D. and Michelle A. Burgess		29 Philbrick Lane	Whitefield	ME	04353
013-024	Jason Stodder		3 Heritage Lane	Wiscasset	ME	04578
013-026	Jay R. Berube		43 Gardiner Road	Whitefield	ME	04353
016-023, 016-024	John and Catherine Purington		129 Cooper Road	Whitefield	ME	04353
030-005	John Dancer & Fred Scott	c/o Fred Scott	22 Village View Lane	Whitefield	ME	04353
030-012-B	John Flagg		31 Melvin Lane	Gardiner	ME	04345
009-031, 010-003	John J. Pagurko III		571 Townhouse Road	Whitefield	ME	04353
004-007	John Mourovic &	Judith Pepper	402 Wiscasset Road	Whitefield	ME	04353
007-013	Johnna E. H. Sheaffer		71 Pine Crest Lane	Whitefield	ME	04353
007-015	Johnna Edith and Lester Edwin Sheaffer, Jr.		71 Pine Crest Lane	Whitefield	ME	04353
001-057-001	Joseph D. Whitmore		516 River Road	Lebanon	ME	04027
007-014-A, 007-014-B	Joseph R. and Elizabeth Heath		17 Village View Lane	Whitefield	ME	04353
004-018-A, 004-019	Josh and Zoe Thomas		10 Misty Mountain Lane	Whitefield	ME	04353
016-040-D	Joshua Grass &	Kasey Blood	24 Stone House Court	Whitefield	ME	04353
009-029	Kathleen and Byron Kelch		493 West River Road	Palatka	FL	32177
004-039-A	Keith and Martha Chase		21 Arbor Hills Drive	Kingston	MA	02364
019-012	Kellie-Jo Labelle	c/o Maine State Credit Union	PO Box 5659	Augusta	ME	04332
007-005, 006-007	Kenneth and Hilary Holm		118 Philbrick Lane	Whitefield	ME	04353
006-008-A	Kenneth and Kimberly Bartlett		104 Philbrick Lane	Whitefield	ME	04353
030-012	Kenneth Hatch III		44 Chamberlain Brook Lane	Whitefield	ME	04353
006-009, 007-019	Kenneth Holm		118 Philbrick Lane	Whitefield	ME	04353
013-009-A	Laurel Banks		95 Town House Road	Whitefield	ME	04353
016-014	Lee and Jennifer Richards		137 Devine Road	Whitefield	ME	04353
001-060	Linda Lank		41 Fourth Street	Bristol	CT	06010
012-059	Lisa M. Hay &	Christine K. Carter	906 Recreation Drive	Corpus Christi	TX	78418
019-031	Lou Anne Story		113 Doyle Road	Whitefield	ME	04353
019-053, 019-053-A	Luke Delano		19 Finn Brook Lane	Whitefield	ME	04353
030-009	Lynnette Russell &	Daniel Conroy	129 Pittston Road	Whitefield	ME	04353
016-040-F	Marc Doyon		16 Stone House Court	Whitefield	ME	04353
016-040-E	Marc Doyon &	Glen Baby	16 Stone House Court	Whitefield	ME	04353
016-035	Mark Labelle		189 Mills Road	Whitefield	ME	04353
004-028	Mark Timko		451 Erico Avenue	Elizabeth	NJ	07202
004-024, 004-025	Martha J. Manchester		77 Mill Road	Edgecomb	ME	04556
007-010, 007-010-A	Nancy Bennett		24 Pleasant Drive	Benton Station	ME	04901
010-011	Nancy Ripley Heirs	c/o Iva M. Ripley, Personal Representative	371 Townhouse Road	Whitefield	ME	04353
001-050, 001-051	Newton Family Real Estate Trust	c/o David R. Newton, Trustee	40 High Street, Apartment #1	Andover	MA	01810
001-045	Noel C. and Peter J. Zeeb		36 Longfellow Avenue	Brunswick	ME	04011
001-048, 001-049	Noel C. and Peter J. Zeeb		32 Soden Street	Cambridge	MA	02139
013-005	Oak Hill Homestead, LLC	c/o Matthew Northrup	266 Townhouse Road	Whitefield	ME	04353
019-051	Osborn M. Delano Heirs		19 Finn Brook Lane	Whitefield	ME	04353
016-039	Osborn M. Delano Life Estate	c/o Luke Delano	19 Finn Brook Lane	Whitefield	ME	04353
019-033, 019-035	Oxford Properties, LLC.		P.O. Box 151	South Paris	ME	04281
019-019, 019-020, 019-030	Patricia Parks		P.O. Box 83	Whitefield	ME	04353
001-058-C	Patrick A. Thayer &	Saramae Edgerly	12 Petticoat Acres Lane	Whitefield	ME	04353



Map Prepared by: Spatial Alternatives
207.846.2355
www.spatialalternatives.com

Tax Sheets are intended for assessing purposes only.
Boundary locations are approximate and
should not be used for conveyance of property.

Town of Whitefield, Maine

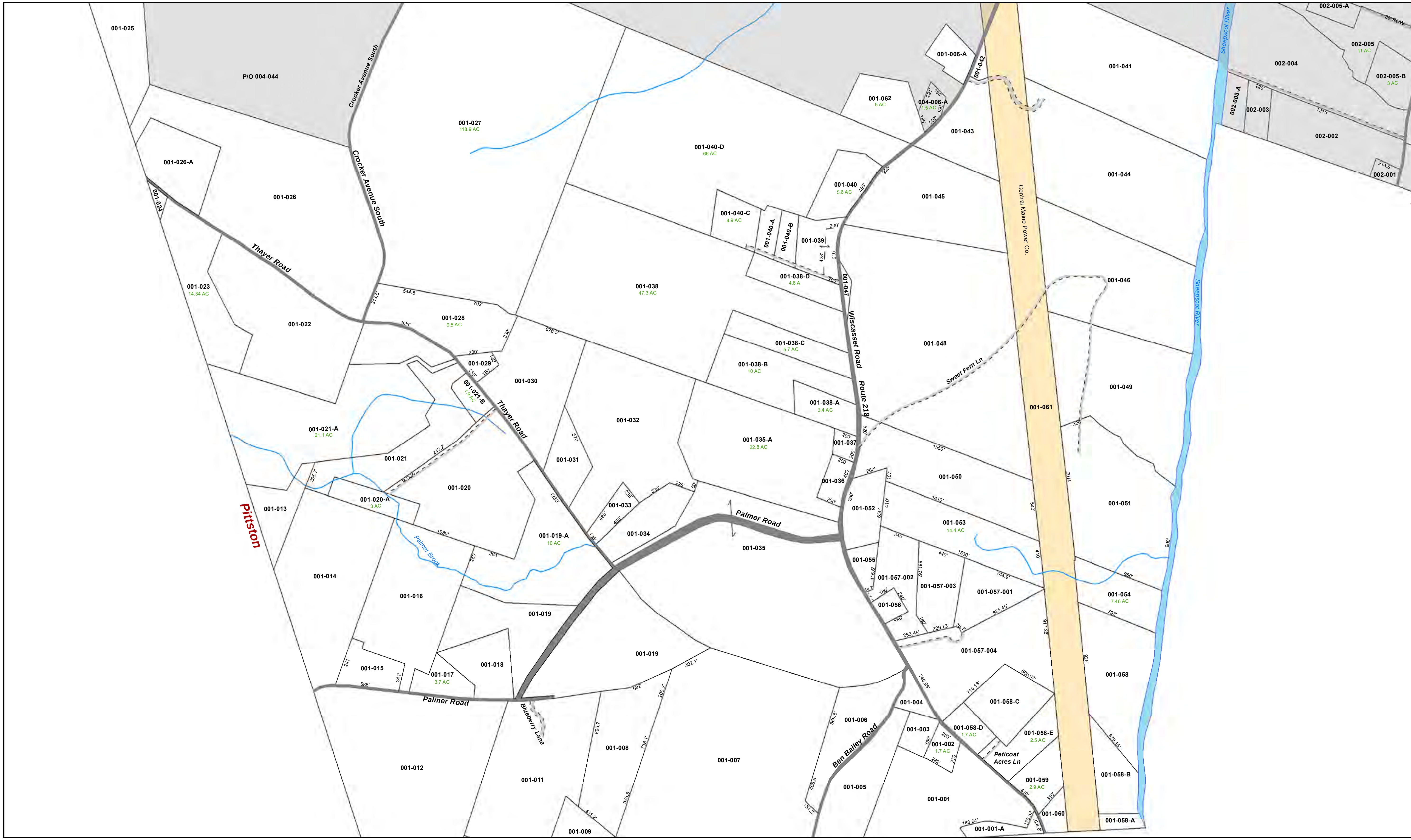
0 1,750 3,500
Feet

N

Whitefield Tax Grid

Index

Map updated to: April 1, 2020



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Stream	PARCEL
Misc	CEMETERY
ROW	UTILITY
Hook	WATER
( ) Merged Parcel	ROAD

Town of Whitefield, Maine

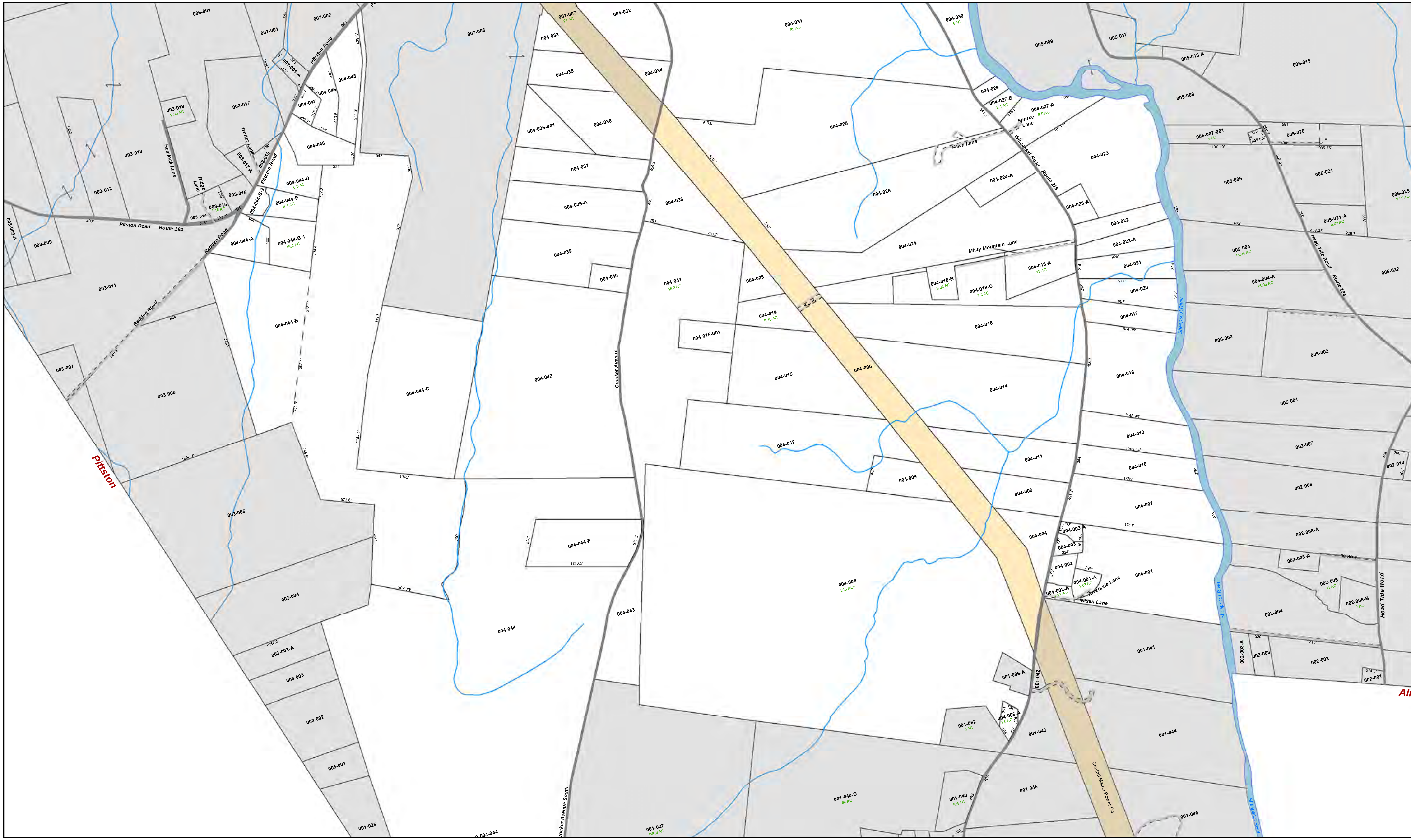
0 500 1,000
Feet

04 02 01

N

Whitefield Tax Grid 01

Map updated to: April 1, 2020



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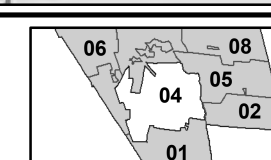
Stream	PARCEL		
Misc	CEMETERY		
ROW	UTILITY		
Hook	WATER		
( ) Merged Parcel	ROAD		

Town of Whitefield, Maine

0 500 1,000 Feet



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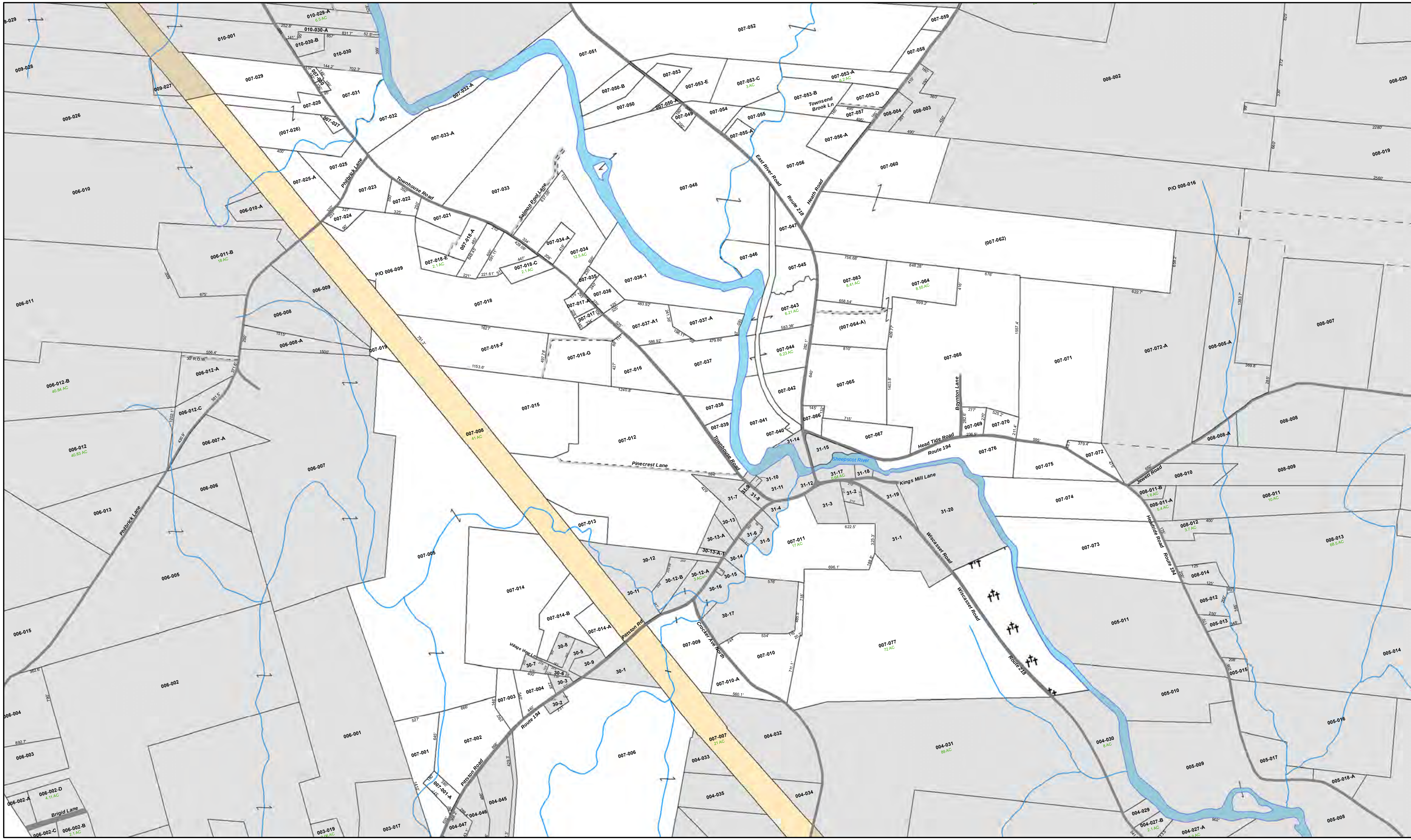
Whitefield Tax Grid 04

Map updated to: April 1, 2020



Map Prepared by: Spatial Alternatives 207.846.2355 www.spatialalternatives.com

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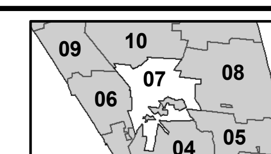
Stream
Misc
ROW
Hook
( ) Merged Parcel
PARCEL
CEMETERY
UTILITY
WATER
ROAD

Town of Whitefield, Maine

0 500 1,000
Feet



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Whitefield Tax Grid
07

Map updated to: April 1, 2020

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Tax Sheets are intended for assessing purposes only. Boundary locations are approximate and should not be used for conveyance of property.

Stream	PARCEL
Misc	CEMETERY
ROW	UTILITY
Hook	WATER
( ) Merged Parcel	ROAD

Town of Whitefield, Maine

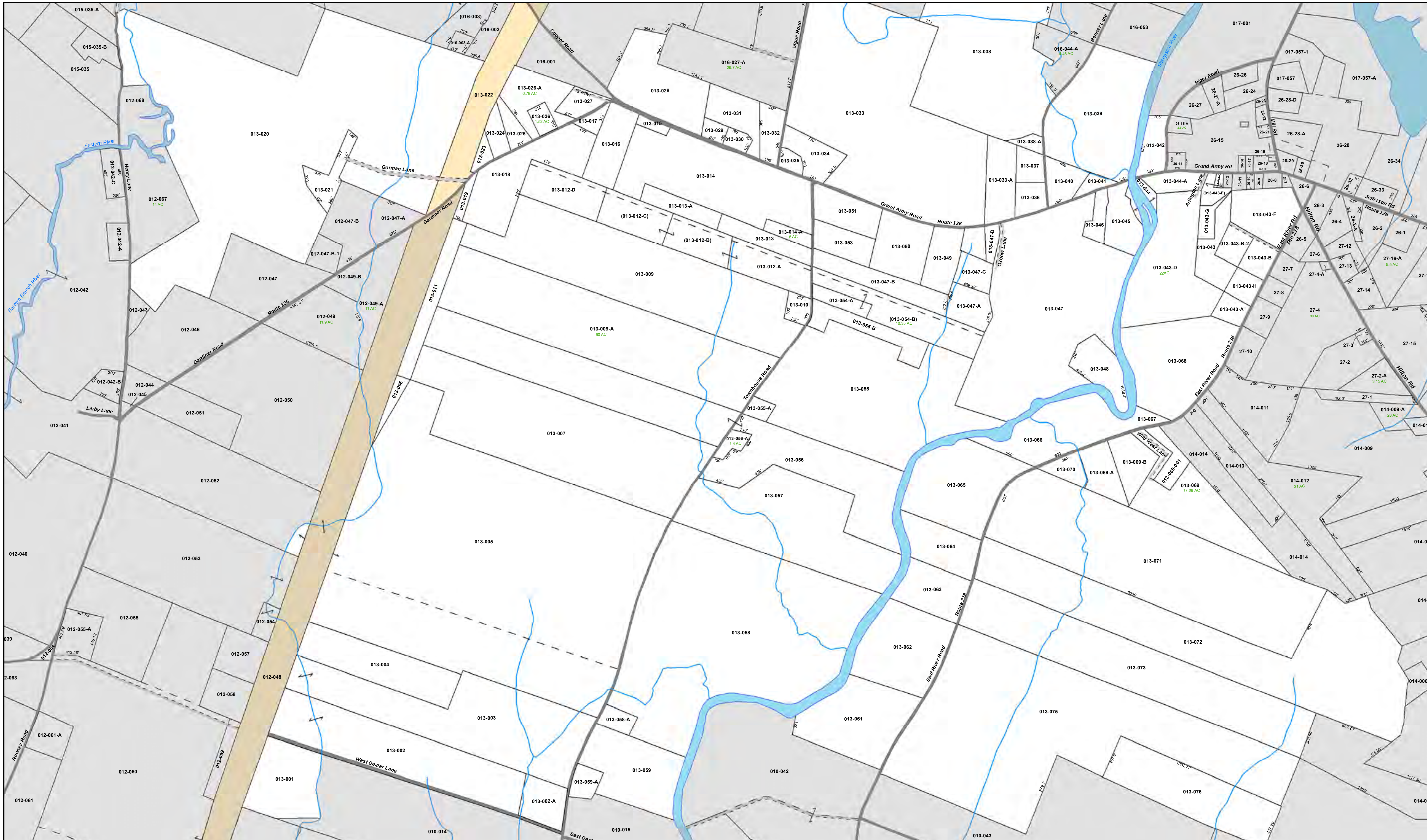
0 500 1,000
Feet

12 13 14
09 10 11
06 07 08

N

Whitefield Tax Grid
10

Map updated to: April 1, 2020



Map Prepared by:

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Stream	PARCEL
Misc	CEMETERY
ROW	UTILITY
Hook	WATER
( ) Merged Parcel	ROAD

Town of Whitefield, Maine

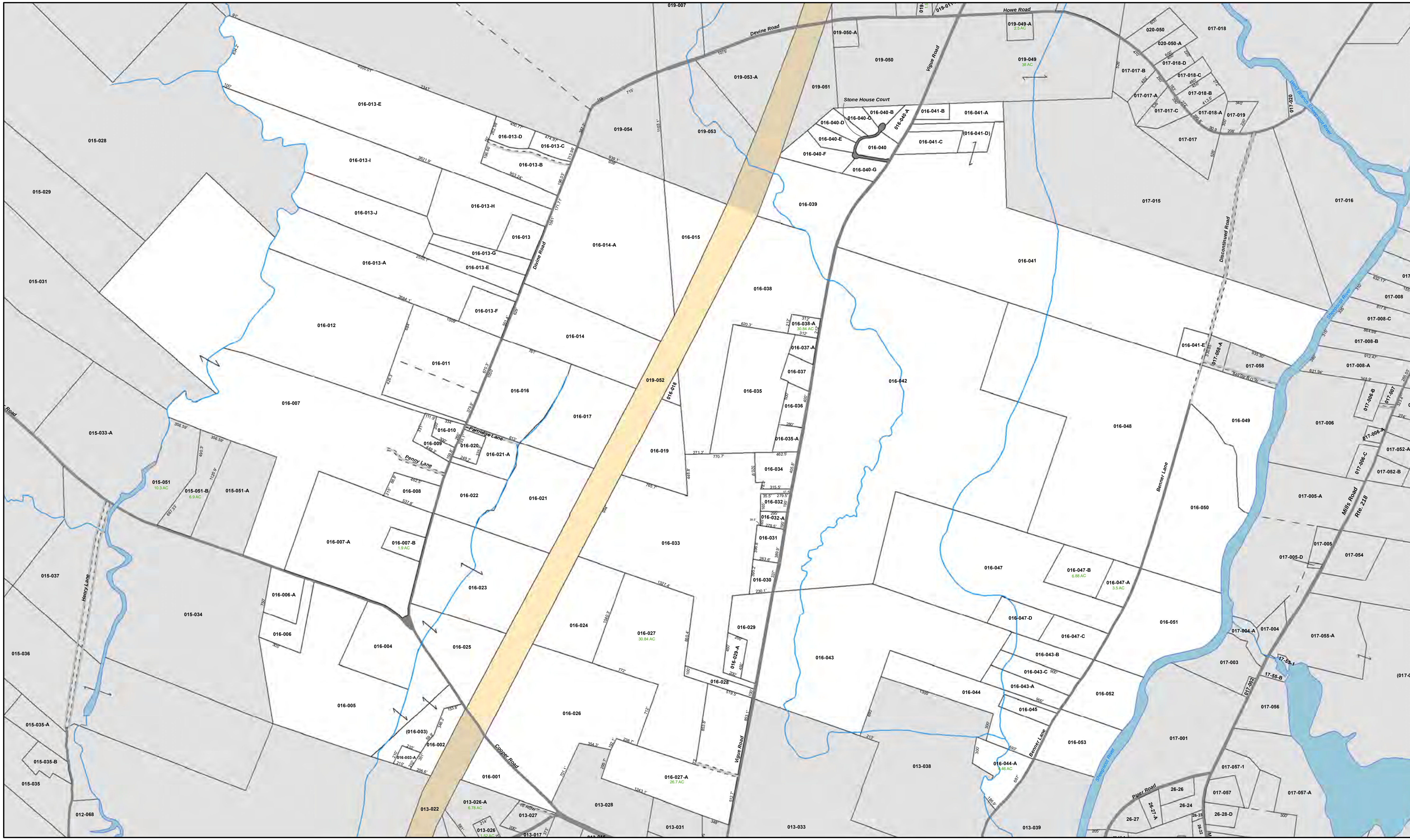
0 500 1,000
Feet

15	16	17
12	13	14
09	10	11

N

Whitefield Tax Grid
13

Map updated to: April 1, 2020



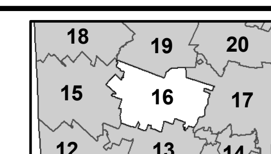
Map Prepared by: Spatial Alternatives 207.846.2355 www.spatialalternatives.com

Tax Sheets are intended for assessing purposes only. Boundary locations are approximate and should not be used for conveyance of property.

Stream	PARCEL
Misc	CEMETERY
ROW	UTILITY
Hook	WATER
( ) Merged Parcel	ROAD

Town of Whitefield, Maine

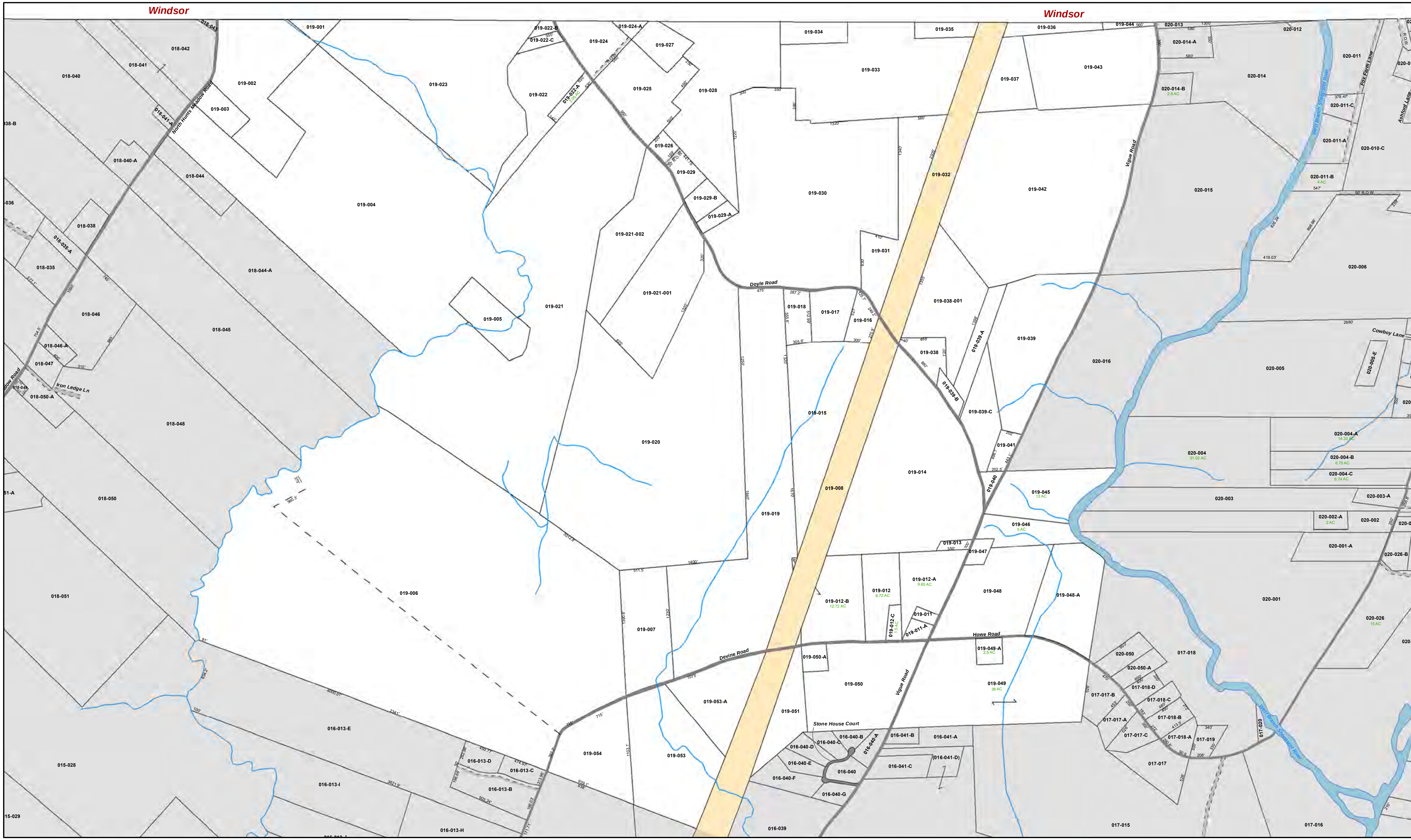
0 500 1,000
Feet



N

Whitefield Tax Grid 16

Map updated to: April 1, 2020



Map Prepared by:

Spatial Alternatives
207.846.2355
www.spatialalternatives.com

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Stream	PARCEL
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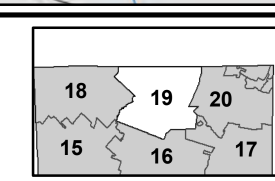

N

Whitefield Tax Grid
19

Map updated to: April 1, 2020

Section 3027 - Whitefield Abutters Within 500'						
010-014	Patrick and Robin Chase		PO Box 142	Whitefield	ME	04353
012-058, 013-002	Patrick C. Chase		P.O. Box 142	Whitefield	ME	04353
019-015, 019-016, 019-017	Paul L. and Alice Leask		122 Doyle Road	Whitefield	ME	04353
009-015-A	Peter A. and Theresa Morin		42 Branch Lane	Whitefield	ME	04353
009-016	Peter A. Morin		42 Branch Lane	Whitefield	ME	04353
001-001-A	Peter and Mary Kromhout		2282 Alna Road	Alna	ME	04535
004-002	Rachel Bennett		432 Wiscasset Road	Whitefield	ME	04353
030-017	Randall Family Revocable Trust		211 Anna Drive	East Bridgewater	MA	02333
016-003, 016-003-A, 016-005	Randolph Sherwood		6117 Rockerfeller Avenue	Sarasota	FL	34231
004-011, 004-012	Regina A. Davey		89 Shamrock Avenue	Damariscotta	ME	04543
019-043	Rhonda Cleaves		PO Box 46	Coopers Mills	ME	04341
001-058-B	Richard and Ida Pipkin Heirs		8 Petticoat Acres Lane	Whitefield	ME	04353
013-056	Richard Howell		114 Town House Road	Whitefield	ME	04353
019-014	Richard L. Cummings, Jr.		P.O. Box 142	Windsor	ME	04363
004-014, 004-015	Richard Mattucci &	Sandra Brown	373 Wiscasset Road	Whitefield	ME	04353
004-031	Richard R. Chase		175 Wiscasset Road	Whitefield	ME	04353
013-019	Robert S. Parlin		90 Gardiner Road	Whitefield	ME	04353
012-047-B	Roberta and Thomas Jamison		143 Gardiner Road	Whitefield	ME	04353
004-033, 004-034, 004-035	Roberta Chase		79 Wiscasset Road	Whitefield	ME	04353
012-049-B	Roger and Carol Franklin		160 Gardiner Road	Whitefield	ME	04353
010-008	Roxanne R and Kenneth Wilson		499 Townhouse Road	Whitefield	ME	04353
004-018	Roy Denham		309 Wiscasset Road	Whitefield	ME	04353
009-018, 019-008-G	Ruth Cushing		465 Townhouse Road	Whitefield	ME	04353
012-050, 013-006	Sam and Carolina Miller		205 Gardiner Road	Whitefield	ME	04353
016-017	Sandra and Charles Picard		121 Devine Road	Whitefield	ME	04353
001-041, 001-042, 004-001	Sheepscot Hollow, LLC		28 Nilsen Lane	Whitefield	ME	04353
007-018. 007-018-E	Sheepscot Links		822 Townhouse Road	Whitefield	ME	04353
016-033. 016-027	Sheepscot Valley Builders	c/o Troy Prescott	P.O. Box 341 - Suite 1	South China	ME	04358
019-036, 019-037	Sherry Boudreau		214 Hunts Meadow Road	Pittston	ME	04345
001-001	Stephen and Ellin Sheehy		757 Wiscasset Road	Whitefield	ME	04353
030-008	Stephen and Lois Bourque		PO Box 57	Whitefield	ME	04353
013-023	Stephen F and Carol P. Acedo		P.O. Box 73	Whitefield	ME	04353
030-001	Stephen Giuffrida		112 Pittston Road	Whitefield	ME	04353
007-028, 009-026, 009-028	Stephen V. and Holly R. Torsey		651 Townhouse Road	Whitefield	ME	04353
016-019	Steven A. McGee		537 High Street	West Gardiner	ME	04345
016-015, 016-038	Steven A. McGee Construction	c/o Steven McGee	537 High Street	West Gardiner	ME	04345
004-037, 004-032	Steven Grady		8 Jewett Lane	Whitefield	ME	04353
001-057-004, 001-058	Susan M. & Gallup C. Westcott, III		714 Wiscasset Road	Whitefield	ME	04353
009-030, 010-002	Thomas and Paula Benne		587 Townhouse Road	Whitefield	ME	04353
010-009	Thomas M. and Lee Ann Szelog		P.O. Box 36	Whitefield	ME	04353
007-023	Timothy and Vicky Morey		695 Town House Road	Whitefield	ME	04353
004-006	Walter R. Chiappini &	Virginia L. Stanley	491 Wiscasset Road	Whitefield	ME	04353
007-006	Watson L. and Edith M. Meck		980 Manor Lane	Southampton	PA	18966
013-007, 013-009	Watson-Moody Enterprises, LLC		163 Town House Road	Whitefield	ME	04353
006-010-A	Wells Fargo Bank, N.A. Trustee for GMACM Mortgage	c/o OCWEN Loan Servicing	1661 Worthington Road	West Palm Beach	FL	33409
004-003-A	Wendy Joslyn		416 Wiscasset Road	Whitefield	ME	04353
012-052, 012-053	William H. Bunting		305 Gardiner Road	Whitefield	ME	04353
004-026	William J. and Judith M. Villeneuve		10 Fawn Lane	Whitefield	ME	04353
004-036	William Rogers		PO Box 57	New Vineyard	ME	04956
016-001, 016-002, 016-025, 016-026	William W. and Gail D. Brooke		41 Cooper Road	Whitefield	ME	04353

EXHIBIT 5 VEGETATION CLEARING PLAN

Central Maine Power

Plan for Protection of Sensitive Natural Resources

During Initial Vegetation Clearing

Prepared by:

Central Maine Power Company
83 Edison Drive
Augusta, Maine 04336

Revised January 2021

CENTRAL MAINE POWER

Introduction

This construction Vegetation Clearing Plan (VCP) applies to construction of the new transmission lines associated with Central Maine Power Company's (CMP) Segment 5 transmission line project extending from Windsor to Wiscasset, Maine. The VCP describes restrictive and protective management practices required for work within and adjacent to protected natural resources during vegetation clearing associated with project construction. This VCP also incorporates specific vegetation management requirements contained in the Maine Department of Environmental Protection (MDEP) Site Location/Natural Resources Protection Act permit issued May 11, 2020. The requirements described in this VCP apply to initial project construction and are not intended to apply to planned or emergency maintenance or repair actions.

The goal of the VCP is to provide construction personnel with a cohesive set of vegetation management specifications and performance standards for work within and adjacent to protected natural resources during transmission line construction.

The protected natural resources subject to restrictive vegetation management requirements include:

- Wetlands and streams (intermittent and perennial);
- Perennial streams within the Segment 5 project ROW;
- All streams (intermittent and perennial) within the Atlantic salmon Gulf of Maine Distinct Population Segment (GOM DPS), which includes the critical habitat;
- Outstanding river segments, rivers, streams or brooks containing threatened or endangered species (e.g., Atlantic salmon);
- State Special Concern Species Habitat: Rusty Blackbird (*Euphagus carolinus*) and Wood Turtle (*Glyptemys insculpta*);
- Significant Vernal Pools (SVP);
- Inland Waterfowl and Wading Bird Habitat (IWWH);
- Deer Wintering Areas (DWA);
- Potential maternal roosting areas for Northern Long-eared Bat (*Myotis septentrionalis*);
- Rare plant locations; and,
- Locations over mapped significant sand and gravel aquifers.

In locations where individual restrictions or procedures overlap, or multiple restrictions apply, the more stringent restrictions and all applicable procedures will be followed by construction personnel.

1.0 Right-of-Way Vegetation Clearing Procedures

1.1 Arboricultural Management Practices

Capable vegetation will be removed and controlled within the footprint of the project ROW. Capable vegetation is defined as woody plant species and individual specimens that can grow to a height that would reach the conductor safety zone, as illustrated in Figure 1 attached to this exhibit. Removal of capable species beneath the conductors within transmission line corridors is intended to meet the following goals:

- Facilitate construction;
- Maintain the integrity and functionality of the line;
- Facilitate safe operation of the line;
- Maintain access in case of emergency repairs; and
- Facilitate safety inspections.

Therefore, the objective of this VCP will be to remove woody vegetation capable of encroaching into the conductor safety zone of the new transmission lines to facilitate construction and maintain the integrity and safe operation of the transmission line consistent with the standards of North American Electric Reliability Corporation's (NERC) Transmission Vegetation Management[1] standard. This will be accomplished by practicing an integrated vegetation management strategy using a combination of mechanical cutting, hand-cutting, and herbicide applications. Mechanical mowing may also be used along access roads or in unusual circumstances, should the typical procedures not suffice.

Throughout clearing and construction, shrub and herbaceous vegetation will remain in place to the extent practicable. Capable vegetation, dead trees, "hazard trees" and all vegetation over 10 feet in height will be removed during initial transmission line corridor clearing prior to construction of the new transmission lines, except in areas described in Section 2.0 below. Due to the sag of the electric transmission lines between the structures, which varies with topography, the distance between structures, tension on the wire, electrical load, air temperature and other variables, the required clearance is typically achieved by removing all capable species from the transmission line corridor. Hazard trees are those trees typically on the edge of the transmission line corridor that pose an imminent threat of violating the minimum separation standard or are at risk of contacting the transmission lines themselves due to disease, configuration or potential instability. Hazard trees are typically removed immediately upon identification.

The following procedures will be implemented during vegetation management activities to protect sensitive natural resources:

[1] North American Electric Reliability Corporation Transmission Vegetation Management, Standard FAC 003 – 3 Technical Reference, July 1, 2014.

a. Protected natural resources and their associated buffers will be flagged or located with a Global Positioning System (GPS) prior to all construction and clearing activities;

b. When and if terrain conditions permit (e.g., certain ravines and narrow valleys) capable vegetation will be permitted to grow within and adjacent to protected natural resources or critical habitats where maximum growing height can be expected to remain well below the conductor safety zone. Narrow valleys are those that are spanned by a single section of transmission line, structure-to-structure.

c. Hand cutting with chainsaws will be the preferred method of vegetation clearing within protected natural resource buffers and sensitive areas, where reasonable and practicable and with the appropriate protective measures. However, mechanized equipment may be used during frozen conditions, or when matted travel lanes and the reach-in technique are implemented;

d. Equipment access through wetlands or over streams will be avoided as much as practicable by utilizing existing public or private access roads, with landowner approval where required;

e. Equipment access in upland areas with saturated soils will be minimized to the extent practicable, or these areas will be matted to avoid excessive rutting or other unnecessary ground disturbance;

f. Disturbance to wetland or stream bank vegetation, if any, will be repaired following completion of clearing activities in the area if exposed soils present a risk of erosion and sedimentation;

g. Areas of significant soil disturbance will be stabilized and reseeded following completion of clearing activities in the area.

h. When capable vegetation within and adjacent to a protected natural resource or identified critical habitat will be removed for constructing the development, the natural regeneration of non-capable woody vegetation will be allowed within all protected resources. At a minimum, the natural regeneration of non-capable woody vegetation will be allowed. To facilitate the regeneration of natural vegetation within and adjacent to (generally, within 75 feet of) protected natural resources and special habitats, the contractor will separate the topsoil from the mineral soil when excavating during project construction. The excavated topsoil will be returned to its original place and position in the landscape and appropriate erosion control methods will be utilized.

i. Locations within the project ROW that contain any of the invasive plant species listed in Table 1 below will be identified prior to the start of construction of the project or the start of construction on any individual segment of the project. CMP has developed an invasive species control plan and submitted it to the MDEP for review and approval prior to the start of construction of the project. This plan has a stated objective of preventing the introduction and spread of invasive species as a result of construction. Herbicide application is an acceptable method of controlling invasive growth when hand removal or other non-chemical methods will not be effective, including in protected natural resources and other sensitive areas.

Table 1 – Invasive Plant Species

Species	Common Name	Form	Indicator
Acer ginnala	Amur maple*	Tree	NI
Acer platanoides	Norway maple*	Tree	NL (upland)
Actinidia arguta	Hardy kiwi	Vine	NI
Aegopodium podagraria	Goutweed*	Herbaceous	FAC
Ailanthus altissima	Tree of heaven*	Tree	NI
Akebia quinata	Chocolate vine; five leaf-	Vine	NI
Alliara petiolata	Garlic mustard*	Herbaceous	NL (upland)
Alnus glutinosa	European alder	Tree	NI
Amorpha fruticosa	False indigo*	Herbaceous	FACW
Ampelopsis glandulosa	Porcelainberry*	Herbaceous	NI
Berberis thunbergii	Japanese barberry*	Shrub	FACU
Berberis vulgaris	Common barberry*	Shrub	FACU
Butomus umbellatus	Flowering rush	Shrub	OBL
Cabomba caroliniana	Fanwort**	Herbaceous	NI
Callitriche stagnalis	Starwort	Herbaceous	NI
Cardamine impatiens	Narrowleaf bittercress	Herbaceous	NI
Celastrus orbiculatus	Oriental bittersweet*	Vine	FACU-
Cirsium arvense	Canada thistle	Herbaceous	FACU
Clematis terniflora	Yam-leaved virgin's bower	Vine	UPL
Cynanchum louiseae	Black swallowwort	Vine	NL (upland)
Cynanchum rossicum	Pale swallowwort	Vine	NI
Dioscorea polystachya	Chinese yam	Vine	NI
Egeria densa	Brazilian waterweed**	Herbaceous	OBL
Elaeagnus umbellata	Autumn olive*	Shrub	FACU
Epilobium hirsutum	Hairy willow-herb	Herbaceous	NI
Euonymus alatus	Winged euonymus*	Shrub	NI
Euonymus fortunei	Wintercreeper	Herbaceous	NI
Euphorbia esula	Leafy spurge	Herbaceous	NI
Fallopia japonica	Japanese knotweed*	Herbaceous	FACU
Fallopia sachalinensis	Giant knotweed	Herbaceous	NI
Fallopia x bohemica	Bohemian knotweed	Herbaceous	NI
Ficaria verna	Lesser celandine	Herbaceous	NI
Frangula alnus	Glossy buckthorn	Shrub	FAC
Glyceria maxima	English water grass	Herbaceous	NI
Heracleum mantegazzianum	Giant hogweed	Herbaceous	NI
Hesperis matronalis	Dame's rocket*	Herbaceous	FACU
Humulus japonicus	Japanese hops	Vine	FACU
Hydrilla verticillata	Hydrilla**	Herbaceous	NI
Hydrocharis morsus-ranae	European frog's bit**	Herbaceous	NI

Species	Common Name	Form	Indicator
Impatiens glandulifera	Ornamental jewelweed*	Herbaceous	FAC
Iris pseudacorus	Yellow iris*	Herbaceous	OBL
Lepidium latifolium	Tall pepperwort	Herbaceous	FACU
Ligustrum obtusifolium	Border privet	Shrub	NI
Ligustrum ovalifolium	California privet	Shrub	NI
Ligustrum vulgare	Privet*	Shrub	NI
Lonicera japonica	Japanese honeysuckle*	Shrub	NI
Lonicera maackii	Amur honeysuckle*	Shrub	NI
Lonicera morrowii	Morrow's honeysuckle*	Shrub	FACU
Lonicera tatarica	Tartarian honeysuckle*	Shrub	FACU
Lonicera x bella	Bella honeysuckle*	Shrub	FACU
Lythrum salicaria	Purple loosestrife*	Herbaceous	OBL
Microstegium vimineum	Japanese stilt grass*	Herbaceous	NI
Myosotis scorpioides	Water forget-me-not	Herbaceous	OBL
Myriophyllum acquaticum	Parrot feather**	Herbaceous	OBL
Myriophyllum heterophyllum	Variable milfoil**	Herbaceous	OBL
Myriophyllum spicatum	Eurasian milfoil**	Herbaceous	OBL
Najas minor	Slender-leaved naiad**	Herbaceous	OBL
Nelumbo lutea	American water lotus	Herbaceous	OBL
Nitellopsis obtusa	Starry stonewort	Herbaceous	NI
Nymphoides peltata	Yellow floating heart**	Herbaceous	NI
Oplismenus hirtellus ssp.	Wavyleaf basketgrass	Herbaceous	NI
Persicaria pertoliata	Mile-a-minute vine*	Vine	NI
Phalaris arundinacea	Reed canary grass	Herbaceous	NI
Phellodendron amurense	Amur cork tree*	Tree	NI
Photinia villosa	Oriental photinia	Shrub	NI
Phragmites australis	Common reed	Herbaceous	FACW
Pistia stratiotes	Water lettuce	Herbaceous	OBL
Populus alba	White cottonwood*	Tree	NI
Potamogeton crispus	Curly pondweed**	Herbaceous	OBL
Pueraria lobata	Kudzu	Vine	NI
Pyrus calleryana	Callery ("Bradford") pear	Tree	NI
Ranunculus repens	Creeping buttercup	Herbaceous	FAC
Rhamnus cathartica	Common buckthorn	Shrub	UPL
Robinia pseudoacacia	Black locust*	Tree	FACU
Rosa multiflora	Multiflora rose*	Shrub	FACU
Rosa rugosa	Rugosa rose	Herbaceous	FACU
Rubus fruticosus	European blackberry	Herbaceous	NI
Rubus phoenicolasias	Wineberry	Herbaceous	NI
Stratiotes aloides	Water soldier	Herbaceous	NI
Thodotypos scandens	Black jetbead	Shrub	NI
Trapa natans	Water chestnut**	Herbaceous	NI
Utricularia inflata	Inflated bladderwort	Herbaceous	OBL

* Plant regulated by the Do Not Sell List, Horticulture Program, Maine Department of Agriculture, Conservation and Forestry.

** Aquatic plant regulated by MDEP.

2.0 Vegetation Clearing and Management Methods

2.1 Mechanical Methods

During construction, vegetative clearing of capable species will be completed primarily with mechanical equipment, including motorized equipment. All capable species and any dead or hazard trees will be cut at ground level except in designated buffer zones, as described below. Large vegetation cut during construction will be handled in accordance with the Maine Slash Law[2]. Any wood that is chipped and spread on the corridor will be left in layers no more than two inches thick, as measured above the mineral soil surface.

As a conservation effort to protect the Northern Long-eared Bat, CMP will suspend tree clearing activities during the maternity roost season of June 1 to July 31. Additionally, initial clearing activities will be performed during frozen ground conditions, to the extent practicable, and, if not practicable, the recommendations of the environmental inspector will be followed regarding the appropriate techniques to minimize disturbance, such as the use of selectively placed travel lanes.

Access roads and travel lanes will be located to protect sensitive and protected natural resources to the maximum extent practicable and construction matting will be used in accordance with CMP's environmental guidelines and per the timber mat performance standards provided below.

Timber mats or matting used for construction:

- shall not be made from wood from ash trees (Fraxinus sp);
- shall be constructed of unfinished timbers free of bark, unless produced by a firm certified by the Maine Forest Service (MFS) for production of mats with incidental bark for this project. Such mats must be marked as outlined in the supplier's agreement. Applicant shall maintain a copy of the MFS compliance agreement including a representation of the accepted mark in the records for agency review, if requested;
- shall be cleaned of soil and vegetative material by pressure washing before entering the State of Maine;
- shall not have been used in, or made from lumber from, Federally Quarantined areas as set out in 7 CFR 301 unless accompanied by the appropriate USDA certificate of treatment required for interstate transport. Said certificates will be maintained in a central filing location available for review by appropriate Agency personnel for a period of three (3) years after project completion, as

2 12 MRS §§ 9331 et seq.

determined by CMP; and

- o must have shipping information sufficient to identify the shipper and number and shipping origin of the mats.

The MFS and U. S. Department of Agriculture will be allowed to inspect timber mats and matting material used for the project for compliance with these standards.

2.2 Herbicide Application

Herbicide applications will likely begin after clearing is completed to gain control of vegetation growth (except for areas listed below where no herbicides will be applied). When control is achieved, treatment will typically occur as part of scheduled maintenance on a 4-year cycle or as needed. By using herbicides, desired vegetation along the transmission line corridor will eventually consist of a dense, low-growing plant community that will discourage the establishment of capable tree species. Therefore, fewer capable woody species and specimens will require treatment in future applications.

The following procedures and restrictions will be implemented during herbicide applications:

a. Herbicides will be used in strict accordance with the manufacturer's EPA-approved labeling and will not be applied directly to waterbodies or areas where surface water is present;

b. In the co-located sections outside the GOM DPS, no foliar herbicides will be applied within 75 feet of rivers, streams, brooks, lakes, ponds, or within 25 feet of wetlands that have water present at the surface at the time of the application.

c. For streams and rivers classified as outstanding river segments, as well as those containing threatened or endangered species (e.g., Atlantic salmon) and coldwater fisheries, and all streams within the GOM DPS that include the critical habitat, no foliar herbicides will be applied within a 100-foot buffer.

d. Herbicides will not be applied to stumps (cut stump treatment) within areas of standing water.

e. Herbicides will not be mixed, transferred or stored within 100 feet of any wetland or surface water. On public access roads, herbicide mixing, transfer or storage may be done within 100 feet of wetlands or surface waters;

f. Herbicides will not be mixed, transferred or stored within 100 feet of Significant Vernal Pool depressions. On public access roads, herbicide mixing, transfer or storage may be done within 100 feet of Significant Vernal Pool depressions;

g. Unless performed on public access roads, herbicides will not be mixed, transferred or stored over mapped significant sand and gravel aquifers;

h. Herbicides will not be applied, mixed, transferred or stored within 100 feet of any known private well or spring or within 200 feet of any known public water supply well. On public access roads, herbicide mixing, transfer or storage may be done within 200 feet of known public water supply wells;

i. When herbicide applications are performed in wetlands without standing water, only herbicides approved for use in wetland environments will be used;

j. Herbicides will not be applied to any area when it is raining or when wind speed exceeds 15 miles per hour as measured on-site at the time of application. When wind speeds are below 3 miles per hour, applicators should be aware of whether a temperature inversion is present, and should consult the herbicide label to determine whether application should proceed under these conditions;

k. The foreman or licensed applicator on each herbicide application crew will be licensed by the Maine BPC and will remain in eye contact and within earshot of all persons on his/her crew applying herbicides. At least one individual from any company applying herbicides will also hold a Commercial Master Applicator License issued by the BPC. This Master Applicator must have the ability to be on-site to assist persons applying herbicides within six hours driving time. If an out-of-state company is conducting the herbicide application, the company will have a Master Applicator in Maine during any application. Application of herbicides will be in accordance with applicable regulations promulgated under the Maine Pesticides Control Act, including those regulations to minimize drift, to maintain setbacks from sensitive areas during application, and to maintain setbacks from surface waters during the storing/mixing/loading of herbicides; and

l. Herbicides will typically be mixed in a truck-mounted tank that remains on public access roads. Herbicide application is done by personnel with low-volume, hand-pressurized (manual) backpacks with appropriate nozzles, to minimize drift, who travel along the transmission line corridor by foot or by all-terrain vehicle and spot-treat target species and specimens.

The location of all streams, wetlands, significant vernal pools, rare plant locations, known wells, and mapped significant sand and gravel aquifers crossed by the transmission line corridor will be provided to construction personnel.

2.3 Petroleum Product & Hazardous Materials Management

Any petroleum products or other hazardous material within the transmission line corridor during construction will be managed in accordance with CMP's Environmental Control Requirements for Contractors and Subcontractors – Oil and Hazardous Material Contingency Plan (see Exhibit 15-1 of the NECEC Site Law Application) and will include the following setbacks unless CMP can demonstrate to the MDEP and USACE that, due to special circumstances at specified locations, these setbacks are impractical at those locations.

(a) No fuel storage, vehicle/equipment parking and maintenance, and refueling activity may occur within 100 feet of a protected wetland or other waterbody, unless no practicable alternative exists and secondary containment with 110% capacity is provided for any fuel storage containers or tanks, or if it occurs on a paved road.

(b) No fuel storage, vehicle/equipment parking and maintenance, and refueling activity may occur within 200 feet of a known private water supply.

(c) No fuel storage, vehicle/equipment parking and maintenance, and refueling activity may occur within 400 feet of a known public water supply.

(d) No fuel storage, vehicle/equipment parking and maintenance and refueling activity may occur within 25 feet minimum of the following:

(i) An area listed in Maine's biological conservation data system, Biotics, of the Maine Natural Areas Program of the Department of Agriculture, Conservation and Forestry (MNAP), including rare natural communities and ecosystems (state rarity rank of S1 through S3 and habitats supporting Endangered or Threatened plant species). Boundaries and locations are as determined by MNAP.

(ii) Habitat of any species declared rare, threatened or endangered by the Maine Department of Inland Fisheries and Wildlife (MDIFW), Maine Department of Marine Resources, or the Director of the U.S. Fish and Wildlife Service.

3.0 Vegetation Clearing and Management within Freshwater Wetlands

Transmission line corridor wetlands range in type from small, emergent wetlands formed in ruts from logging equipment to large forested wetland systems.

3.1 Vegetation Clearing Restrictions within and Adjacent to Freshwater Wetlands

The following restrictions apply to vegetation clearing within freshwater wetlands and their buffers:

a. Unless frozen, heavy equipment travel in wetlands will be performed on construction matting, or other approved alternative protective measures will be implemented.
b. If initial clearing or other construction activities result in areas of bare soil or minimally vegetated cover, these areas will be allowed to revegetate naturally, where practicable. If areas are sufficiently large to warrant planting, a native seed designed to provide short term cover will be applied, and the area will be allowed to return to non-capable native woody and perennial herbaceous vegetation naturally.
c. No accumulation of slash will be left within wetlands.

4.0 Vegetation Clearing within Stream Buffers (Riparian Filter Areas)

Stream buffers, as measured horizontally from the top of each stream bank, will be established for vegetation removal along streams within the transmission line corridor. A "stream buffer" is a buffer on a stream, river, or brook. In no case may the stream buffer be reduced to less than 75 feet. Additional restrictions will be applied within 100 feet of streams meeting certain criteria, as described in Section 4.1 below.

This section describes the additional restrictions related to vegetation removal within these stream buffers. All vegetation clearing procedures and restrictions that apply to vegetation management for transmission line corridor construction also apply within the stream buffers.

4.1 Additional Vegetation Clearing Restrictions within Stream Buffers

The following additional restrictions apply to vegetation clearing within stream buffers:

a. Riparian natural buffers (or "stream" buffers) will be retained within 100 feet of all streams (intermittent and perennial) in the GOM DPS, all perennial and coldwater fishery streams within Segment 1 of the Project and all coldwater fisheries in other segments, outstanding river segments, or rivers, streams, or brooks containing Threatened or Endangered species (e.g., Atlantic salmon) unless the MDEP determines that the functions and values of the stream buffer will not be impacted by the removal of vegetation and approves an alternative minimum buffer.

b. For streams in areas where the new transmission line will be co-located within existing rights-of-way, CMP proposes to maintain a 75-foot buffer, unless meeting any of the above criteria, since the existing corridor is currently being maintained in an early successional state according to the guidelines set forth in CMP's Vegetation Management Plan (Exhibit D), and the effect of the additional clearing (typically less than 75 feet) to accommodate the new line has been minimized.

c. The boundary of each stream buffer will have unique flagging installed to distinguish between the applicable 75-foot or 100-foot stream buffer prior to clearing. Flagging will be maintained throughout construction.

d. Foliar herbicides will be prohibited within the stream buffer, and all refueling/maintenance of equipment will be excluded from the buffer unless it occurs on an existing paved road or if secondary containment is used with oversight from an environmental inspector.

e. All stream crossings by heavy equipment will be performed through the installation of equipment spans with no in-stream disturbances. Streams will not be forded by heavy equipment.

f. Initial tree clearing will be performed during frozen ground conditions whenever practicable, and if not practicable, the recommendations of the environmental inspector will be followed regarding the appropriate techniques to minimize disturbance such as the use of selectively placed travel lanes within the stream buffer. CMP will not place any transmission line structures within the stream buffer, unless specifically authorized by the MDEP and accompanied by a site-specific erosion control plan. No structures will be placed within 25 feet of any stream regardless of its classification.

g. Within that portion of the stream buffer that is within the wire zone (i.e., within 15 feet, horizontally, of any conductor; see Figure 1), all woody vegetation over 10 feet in height, whether capable or non-capable, will be cut back to ground level and resulting slash will be managed in accordance with Maine's Slash Law. No other vegetation, other than dead or hazard trees, will be removed. Within the stream buffer and outside of the wire zone, non-capable species may be allowed to exceed 10 feet in height unless it is determined that they may encroach into the conductor safety zone prior to the next four year maintenance cycle. Vegetation maintenance within Segment 1 will be on a two- to three-year cycle and must not exceed a three-year cycle within any particular area within this segment without prior approval from the MDEP;

h. Removal of capable species and dead or hazard trees within the stream buffer will typically be accomplished by hand-cutting. Use of mechanized harvesting equipment is allowed if supported by construction matting or during frozen conditions in a manner (i.e., use of travel lanes and reach-in techniques) that preserves non-capable vegetation less than 10 feet in height to the greatest extent practicable. Within the wire zone all woody vegetation may be cut to ground level;

i. No slash will be left within 50 feet of any stream; and,

j. Any construction access roads that must cross streams or brooks must be designed, constructed, and maintained to minimize erosion and sedimentation.

Allowing non-capable vegetation to remain as described above within the stream buffer will provide shading and reduce the warming effect of direct sunlight (insolation). Low ground cover vegetation will also remain to filter any sediment in surface runoff. These restrictions will allow the stream buffers to provide functions and values similar to those provided prior to transmission line construction.

5.0 Vegetation Clearing within Significant Vernal Pool Habitat (SVPH)

Vegetated buffers of 250 feet, as measured from the edge of the pool depression, will be established for SVPs crossed by the transmission line corridor. The SVP depression and buffer area together comprise the SVPH. Vegetation clearing within the SVPH will be subject to the same procedures and prohibitions, as applicable, that are required in the typical transmission line corridor, as well as to the additional measures below.

5.1 Additional Vegetation Management Restrictions within SVPH

The following additional restrictions apply to vegetation clearing within SVPH:

a. Mechanized equipment will not be allowed within the vernal pool depression, unless the depression encompasses the entire width of the transmission line corridor. Mechanized equipment will only be allowed to cross the vernal pool depressions during frozen or dry conditions or with the use of mats;

b. Initial clearing within a SVPH will occur during frozen ground conditions. If not practicable, hand cutting or reach-in techniques will be used. If that is not adequate, travel lanes to accommodate mechanical equipment in the 250-foot buffer may be used with approval of the MDEP.

c. Between April 1 and June 30 in any calendar year, no vegetation removal using tracked or wheeled equipment will be performed within the 250-foot SVPH ;

d. No refueling or maintenance of equipment, including chainsaws, will occur within 250 feet of SVP depressions, unless conducted on a public access road;

e. No herbicide use is permitted within 25 feet of the SVP pool depression; and

f. No accumulation of slash will be left within 50 feet of the edge of the SVP depression and slash piles will not exceed 18 inches tall.

6.0 Vegetation Clearing within Moderate or High Value Inland Waterfowl and Wading Bird Habitat

Inland Waterfowl and Wading Bird Habitats (IWWH) are habitats mapped by the MDIFW that contain an inland wetland complex used by waterfowl and wading birds, plus a 250-foot nesting habitat area surrounding the wetland. The nesting habitat is part of the mapped IWWH. No additional buffers are proposed for IWWHs beyond this mapped habitat, and as such the vegetation maintenance restrictions apply to the mapped habitat only.

A survey for Great Blue Heron colonies within or immediately adjacent to existing IWWH will be conducted by CMP between April 20 and May 31, and prior to initial transmission line clearing. If any colonies are identified, CMP will consult with MDIFW and obtain approval from the MDEP prior to construction in the vicinity of any colony.

Vegetation clearing within the IWWH will be subject to the same procedures and prohibitions, as applicable, that are required in the typical transmission line corridor and for stream buffers.

6.1 Additional Vegetation Clearing Restrictions within Inland Waterfowl and Wading Bird Habitat

The following additional restrictions apply to vegetation clearing within mapped IWWH:

a. If practicable, vegetation clearing will take place during frozen ground conditions. If not practicable, vegetation within IWWH will be removed using hand cutting or reach-in techniques and appropriate techniques to minimize disturbance to the maximum extent practicable, such as the use of travel lanes to accommodate mechanical equipment use in the IWWH.

b. Between April 15 and July 15, use of motorized vehicles (e.g., all-terrain vehicles) and mechanized equipment (e.g., chainsaws or brush cutters) within IWWH is prohibited. Use of non-mechanized hand tools is allowed during this time period;

c. No refueling or maintenance of equipment, including chainsaws, will occur within the IWWH, unless done so on a public access road; and

d. No herbicide use is permitted within 25 feet of any wetland within the mapped IWWH.

e. Where overhead transmission lines cross an IWWH area, CMP will install bird diverters or aviation marker balls according to the manufacturer's guidelines and applicable transmission line codes unless otherwise determined to be impracticable by the MDEP in consultation with MDIFW.

f. Provided they do not present a safety hazard and are naturally present, CMP will leave undisturbed a minimum of 2-3 snags per acre to provide nesting habitat for waterfowl. Where appropriate, to mitigate habitat impacts due to the development, and as approved by the MDEP, capable species will be topped, girdled, and/or treated with herbicides (except in areas where herbicides are prohibited per this Plan) to prevent re-growth to create snags. Snags will be 12-16 inch in diameter or the largest size available from the existing stand of vegetation.

g. No accumulation of slash will be left within the IWWH.

h. Impacts to scrub-shrub and herbaceous vegetation within the IWWH will be minimized to the maximum extent practicable.

7.0 Vegetation Clearing within Mapped Deer Wintering Areas

Deer Wintering Areas (DWA) provide important refuge for white-tailed deer (*Odocoileus virginianus*) during the winter months in northern climates and are typically characterized by an extensive stand of mature softwood species with a dense forest canopy.

During construction, impacts to scrub-shrub and herbaceous vegetation and other non-capable species will be minimized to the maximum extent practicable. No additional vegetation clearing restrictions are proposed within mapped DWAs in the co-located portions of the Project, as all capable species will be removed from these and other areas within the transmission line corridor to comply with NERC Transmission Vegetation Management standards. Clearing restrictions within the Upper Kennebec DWA are provided below. To enhance wildlife habitat in and adjacent to DWAs, including the Upper Kennebec DWA, disturbed soils in upland areas will be revegetated with a Wildlife Seed Mix, promoted by the Sportsman's Alliance of Maine (SAM) and developed with Maine Seed Company. This wildlife-friendly seed mix will offer nutrition to deer and other wildlife such as moose, rabbits, ruffed grouse, geese, and wild turkeys during late fall and early spring when woods forage is sparse. The tender shoots derived from SAM's seed mix offer forage that is high in calories and protein, and are highly digestible to deer.[3]

[3] Lavigne, G., Experimental Wildlife Seed Mix Available through SAM, Maine Forest Products Council, June 2013.

8.0 Vegetation Clearing within State-mapped Rusty Blackbird Habitat

In consultation with MDIFW, CMP agreed to allow for the retention of 10-foot to 15-foot tall spruce/fir vegetation within any Rusty Blackbird habitat. The additional height will avoid project impacts to habitat of this State Species of Special Concern.

Clearing activity is prohibited in this habitat between April 20 and June 30. During the initial vegetation clearing for construction activities, all capable hardwood species and softwood specimens over 15 feet in height, as well as those anticipated to grow taller than 15 feet in height prior to the next scheduled vegetation maintenance, will be cut at ground level and removed. Spruce/fir vegetation 10-15 feet in height will be retained. The access roads and structure preparation areas within the Rusty Blackbird habitat will be cleared of all capable and non-capable species and maintained as scrub-shrub habitat to allow for post-construction maintenance, repair and/or emergency access during operation of the line. The habitat will be flagged prior to construction and identified in a database maintained by CMP, further described in Section 12.0.

9.0 Wood Turtle Habitat

Clearing activity is prohibited in mapped wood turtle habitat between April 16 and October 14.

10.0 Vegetation Clearing within Rare Plant Locations

Vegetation clearing of the transmission line corridor has the potential to impact rare plants and/or alter their habitat. The following additional vegetative clearing restrictions will minimize such impacts. The additional restrictions will apply only to the demarcated locations of the identified rare plants. No additional buffers will be established surrounding rare plant locations. These restrictions are intended to maintain existing hydrology and limit soil disturbance within rare plant locations.

10.1 Additional Vegetation Clearing Restrictions within Rare Plant Locations

The following additional restrictions will apply to vegetation clearing for rare plant species in the identified location:

a. Unless rare plant locations encompass the entire width of the transmission line corridor, mechanized equipment will only be allowed to cross rare plant locations during frozen conditions, on established travel paths/crossings, or with the use of mats.

b. Initial clearing within rare plant communities will be undertaken during frozen ground conditions whenever practicable, and if not practicable selective mat placement and reach-in techniques will be used to minimize disturbance to the rare plant communities to the maximum extent practicable.

c. If initial clearing or other construction activities result in areas of bare soil or minimally vegetated cover, where practicable, these areas will be allowed to revegetate naturally. If areas are sufficiently large to warrant planting, a native seed mix designed to provide short term cover will be applied and the area will be allowed to return to native woody and perennial herbaceous vegetation naturally.

d. Heavy equipment travel within rare plant communities will be minimized to the maximum extent practicable. Hand cutting or reach-in techniques to cut and remove capable tree species and vegetation over 10 feet tall within the wire zone, or other techniques as agreed upon in consultation with the MDEP and MNAP, will be used. When equipment access is necessary, activity will be restricted to a few narrow travel lanes that have been clearly marked prior to clearing activity.

e. No refueling or maintenance of equipment, including chain saws, will occur within demarcated rare plant locations, unless done on a public access road.

f. No foliar herbicide use is permitted within the demarcated rare plant locations, however cut surface herbicides may be used on capable species and specimens outside of Segment 1.

11.0 Vegetation Clearing Procedures over Mapped Significant Sand and Gravel Aquifers

Transmission lines located over mapped significant sand and gravel aquifers are subject to the typical transmission line corridor clearing procedures, except that no refueling or maintenance of equipment, and no herbicides may be mixed, transferred or stored, over the mapped significant sand and gravel aquifers, unless done so on a public access road.

12.0 Locating and Marking Buffers and Habitats

A database will be maintained, including maps and GIS shapefiles, of the buffers, restricted habitats, and sensitive areas and their locations relative to the nearest structure or road location. The distance and direction from the nearest structure to the sensitive area will be included with the name of the area and the structure number. All structures along the transmission line corridor will be numbered at the time of construction.

To aid in identifying restricted areas, buffers and restricted habitats will be located and demarcated in the field using brightly colored flagging or signage prior to the initiation of clearing and construction activities along the transmission line corridor. Alternatively, use of GIS data and GPS equipment may be used to provide accurate location of resources and associated buffers. If desired, personnel may permanently demarcate restricted habitats to aid in construction activities. Personnel working on the transmission line corridor will be provided a copy of this VCP. Use of the VCP in conjunction with the natural resource maps and Plan & Profile drawings will enable construction contractors to locate and mark restricted areas in the field.

13.0 Personnel Training

Personnel who will conduct vegetation clearing on the transmission line corridor will receive appropriate environmental training before being allowed access to the transmission line corridor. Construction and clearing personnel will be required to review this VCP prior to the training and before conducting any clearing or construction activities. The level of training will be dependent on the duties of the personnel. The training will be given prior to the start of clearing or construction activities. Replacement or new clearing or construction personnel that did not receive the initial training will receive similar training prior to performing any activities on the transmission line corridor.

The training session will consist of a review of the buffers and restricted habitats, the respective vegetation clearing requirements and restrictions for each, and a review of how these areas and resources can be located in the field. Training will include familiarization with and use of GIS information and sensitive natural resource identification in conjunction with the contents of this VCP, as well as basic causes, preventive and remedial measures for contamination, and erosion and sedimentation of water resources.

EXHIBIT 6 VEGETATION MAINTENANCE PLAN

Central Maine Power Company

Post-Construction Vegetation Maintenance Plan

Prepared by:

Central Maine Power Company
83 Edison Drive
Augusta, Maine 04336

Revised January 2021

Introduction

This post-construction Vegetation Maintenance Plan (VMP) describes the restrictive maintenance requirements for protected natural resources within Central Maine Power Company's (CMP) Segment 5 project transmission line corridor, which extends from Windsor to Wiscasset, Maine. The requirements described in this VMP apply to routine maintenance and are not intended to apply to emergency maintenance and/or repair actions.

The goal of this VMP is to provide maintenance personnel and contractors with a cohesive set of vegetation maintenance specifications for transmission line corridor. This VMP is intended to be used in conjunction with project As-Built Plan & Profile drawings to locate the areas where maintenance restrictions apply.

The protected natural resources and visually sensitive areas subject to restrictive and protective maintenance requirements include:

- Wetlands and streams (intermittent and perennial);
- All streams (intermittent and perennial) within the Atlantic salmon Gulf of Maine Distinct Population Segment (GOM DPS), which includes the critical habitat;
- Outstanding river segments, rivers, streams or brooks containing threatened or endangered species (e.g., Atlantic salmon);
- State Special Concern Species Habitat: Rusty Blackbird (*Euphagus carolinus*) and Wood Turtle (*Glyptemys insculpta*);
- Significant Vernal Pools (SVP);
- Inland Waterfowl and Wading Bird Habitat (IWWH);
- Deer Wintering Areas (DWA);
- Potential maternal roosting areas for Northern Long-eared Bat (*Myotis septentrionalis*);
- Rare plant locations;
- Locations over mapped significant sand and gravel aquifers; and
- Viewpoints from Coburn Mountain and Rock Pond.

In locations where individual restrictions or procedures overlap or multiple restrictions apply, the more stringent restrictions and all applicable procedures will be followed by maintenance personnel and contractors.

1.0 Right-of-Way Vegetation Maintenance Procedures

1.1 Typical Maintenance Procedures

Routine vegetation maintenance for transmission line corridors is intended to meet the following goals:

1. Maintain the integrity and functionality of the line;
2. Facilitate safe operation of the line;
3. Maintain access in case of emergency repairs; and
4. Facilitate safety inspections.

Therefore, the objectives of this VMP will be to control the growth of woody vegetation capable of encroaching into the conductor safety zone of the transmission line to ensure the integrity and safe operation of the transmission line consistent with the standards of North American Electric Reliability Corporation's (NERC) Transmission Vegetation Management. [1] This will be accomplished by practicing an integrated vegetation management strategy using a combination of hand-cutting and selective herbicide applications. Mechanical mowing may be used in unusual circumstances to regain control of vegetation, should the typical procedures not suffice.

Throughout clearing and construction, shrub and herbaceous vegetation will remain in place to the extent possible. Removing capable vegetation will be done during initial transmission line corridor clearing prior to construction of the new transmission line. Follow-up maintenance activities during operation of the line require the removal of capable species, dead trees, and hazard trees. Capable trees are those plant species and individual specimens that are capable of growing tall enough to violate the required clearance between the conductors and vegetation established by NERC. Due to the sag of the electric transmission lines between the poles, which varies with the distance between poles, topography, tension on the wire, electrical load, air temperature, and other variables, the required clearance is typically achieved by removing all capable species during each maintenance cycle. Removing capable species vegetation allows for the maintenance of 25 feet of separation between vegetation and the lines, thereby adhering to NERC standards. Hazard trees are those trees typically on the edge of the transmission line corridor that pose an imminent threat to violating the minimum separation standard (minimum distance allowed between conductors and adjacent vegetation varies depending on voltage) or are at risk of contacting the lines themselves. Hazard trees are typically removed immediately upon identification.

More frequent vegetation management may be required within the first 3 to 4 years following construction in order to bring the vegetation under control. After this initial management period, maintenance practices are typically carried out on a 4-year cycle depending on growth, weather, geographic location, and corridor width. Maintenance may be required less frequently in the long-term as vegetation within the corridor becomes dominated by shrub and herbaceous species. Large branches that overhang the transmission line corridor and any hazard trees on the edge of, or

[1] North American Electric Reliability Corporation Transmission Vegetation Management, Standard FAC 003 – 3 Technical Reference, July 1, 2014.

outside of, the transmission line corridor that could contact the electrical lines or come within 15 feet of a conductor may be removed as soon as they are identified.

The following procedures will be implemented during vegetation maintenance activities to protect sensitive natural resources:

- Protected resources and their associated buffers will be flagged or located with a Global Positioning System (GPS) prior to all maintenance operations;
- Hand-cutting will be the preferred method of vegetation maintenance within buffers and sensitive areas, where reasonable and practicable;
- Equipment access through wetlands or over streams will be avoided as much as practicable by utilizing existing public or private access roads, with landowner approval where required;
- Equipment access in upland areas with saturated soils will be minimized to the extent practicable to avoid rutting or other ground disturbance;
- Significant damage to wetland or stream bank vegetation, if any, will be repaired following completion of maintenance activities in the area; and
- Areas of significant soil disturbance will be stabilized and reseeded following completion of maintenance activity in the area.

2.0 Vegetation Maintenance Methods

2.1 Mechanical Methods

During routine vegetation maintenance after construction, mechanical methods of maintaining the height of vegetation on the transmission line corridor will consist primarily of cutting with hand tools, with occasional use of chainsaws and limited use of motorized equipment in areas directly accessible from public or private access roads.

Maintenance procedures will be to cut all capable species and any dead or hazard trees at ground level except in designated areas, as described below. Large vegetation cut during routine maintenance will be handled in accordance with the Maine Slash Law.[2] Any wood that is chipped and spread on the corridor shall be left in layers no more than two inches thick, as measured above the mineral soil surface.

Additionally, as a conservation effort to protect the Northern Long-eared Bat, CMP will suspend vegetation maintenance activities for trees greater than 3 inches diameter at breast height during the maternity roost season of June 1 to July 31.

2 12 M.R.S. §§ 9331 et seq.

2.2 Herbicide Application

Herbicide application will be used in conjunction with mechanical methods of vegetation maintenance. The herbicide application program is consistent with most New England utilities and consists of direct application to targeted species and specimens along the transmission line corridor with a low-volume foliar herbicide or application of herbicides to cut stumps and surfaces of larger trees. Direct application to individual plant species, as opposed to a broadcast spray, will target woody vegetation allowing low-growing plant communities (the desired shrub and herbaceous species) to thrive. Herbicides will also be selectively applied to minimize the impacts to non-target species. Aerial application will not be done. Only herbicides which are registered with and approved by the U.S. Environmental Protection Agency (EPA-approved) and registered with the Maine Board of Pesticides Control (BPC) will be used.

Herbicide applications will likely begin the first year after construction is completed to gain control of vegetation growth (with the exception of areas listed below where no herbicides will be applied). When control is achieved, treatment will typically occur on a 4-year cycle or as needed. By using selective herbicides and a variety of application methods, vegetation along the transmission line corridor will eventually consist of a dense, low-growing plant community that will discourage the establishment of tree species. Therefore, fewer woody species will require treatment in future applications.

The following procedures and restrictions will be implemented during herbicide applications:

- Herbicides will be used in strict accordance with the manufacturer's EPA-approved labeling and will not be applied directly to waterbodies or areas where surface water is present;
- Throughout the Project corridor no foliar herbicides will be applied within a 100-foot buffer of all coldwater fishery[3] streams, or within a 75-foot buffer of intermittent streams;
- In co-located sections outside the GOM DPS, foliar herbicides will not be applied within 75 feet of rivers, streams, brooks, lakes, ponds, or within 25 feet of wetlands that have water present at the surface at the time of the application;
- For all streams within the GOM DPS which includes the critical habitat, streams and rivers classified as a coldwater fishery, and outstanding river segment or streams containing threatened or endangered species (e.g., Atlantic salmon), foliar herbicides will not be applied within a 100-foot buffer;
- Herbicides will not be mixed, transferred or stored within 100 feet of any wetland or surface water, unless done so on a public access road;
- Herbicides will not be mixed, transferred or stored within 100 feet of Significant Vernal Pool depressions, unless done so on a public access road;

[3] The term coldwater fishery, as used in this document, pertains to streams that are known to contain brook trout as designated by the Maine Department of Inland Fisheries and Wildlife (MDIFW).

- Herbicides will not be mixed, transferred or stored over mapped significant sand and gravel aquifers unless done so on a public access road;
- Herbicides will not be applied, mixed, transferred or stored within 100 feet of any known private well or spring or within 200 feet of any known public water supply well, unless done so on a public access road;
- When herbicide applications are performed in wetlands without standing water, only herbicides approved for use in wetland environments will be used;
- Herbicides will not be applied to any area when it is raining or when wind speed exceeds 15 miles per hour as measured on-site at the time of application. When wind speeds are below 3 miles per hour, applicators should be aware of whether a temperature inversion is present, and should consult the herbicide label to determine whether application should proceed under these conditions;
- The foreman or licensed applicator on each herbicide application crew will be licensed by the Maine BPC and will remain in eye contact and within earshot of all persons on his/her crew applying herbicides. At least one individual from any company applying herbicides must also hold a Commercial Master Applicator License issued by the BPC. This Master Applicator must have the ability to be on-site to assist persons applying herbicides within six hours driving time. If an out-of-state company is conducting the herbicide application, the company must have a Master Applicator in Maine during any application. Application of herbicides will be in accordance with applicable regulations promulgated under the Maine Pesticides Control Act, including those regulations to minimize drift, to maintain setbacks from sensitive areas during application, and to maintain setbacks from surface waters during the storing/mixing/loading of herbicides; and
- Herbicides will typically be mixed in a truck-mounted tank that remains on public access roads. Herbicide application is done by personnel with low-volume, hand-pressurized (manual) backpacks with appropriate nozzles, to minimize drift, who travel along the transmission line corridor by foot or by all-terrain vehicle and spot-treat target species and specimens.

The location of all streams, wetlands, significant vernal pools, rare plant locations, known wells, and mapped significant sand and gravel aquifers crossed by the transmission line corridor will be shown on the As-Built Plan & Profile drawings. GIS shapefiles will also be maintained with the location of these resources and will be provided to maintenance personnel. The presence of surface water will be determined prior to herbicide use in any wetland or waterbody. Crew leaders will assure that resources and buffers are clearly marked in the field, or that locations of resources and buffers are provided as GIS/GPS data prior to initiation of an herbicide application for clear identification by the applicators.

2.3. Petroleum Products & Hazardous Materials Management

Any petroleum products or other hazardous material within the transmission line corridor during construction will be managed in accordance with CMP's Environmental Control Requirements for Contractors and Subcontractors – Oil and Hazardous Material Contingency Plan (see Exhibit 15-1 of the NECEC Site Law Application) and will include the following setbacks unless CMP can demonstrate that, due to special circumstances at specified locations, these setbacks are impractical at those locations.

(a) No fuel storage, vehicle/equipment parking and maintenance, and refueling activity may occur within 100 feet of a protected wetland or other waterbody, unless no practicable alternative exists and secondary containment with 110% capacity is provided for any fuel storage containers or tanks, or if it occurs on a paved road.

(b) No fuel storage, vehicle/equipment parking and maintenance, and refueling activity may occur within 200 feet of a known private water supply.

(c) No fuel storage, vehicle/equipment parking and maintenance, and refueling activity may occur within 400 feet of a known public water supply.

(d) No fuel storage, vehicle/equipment parking and maintenance and refueling activity may occur within 25 feet minimum of the following:

(i) An area listed in Maine's biological conservation data system, Biotics, of the Maine Natural Areas Program of the Department of Agriculture, Conservation and Forestry (MNAP), including rare natural communities and ecosystems (state rarity rank of S1 through S3 and habitats supporting Endangered or Threatened plant species). Boundaries and locations are as determined by MNAP.

(ii) Habitat of any species declared rare, threatened or endangered by MDIFW, Maine Department of Marine Resources, or the Director of the U.S. Fish and Wildlife Service.

3.0 Vegetation Maintenance within Freshwater Wetlands

Transmission line corridor wetlands range in type from small, emergent wetlands formed in ruts from logging equipment to large forested wetland systems. No specific buffers are proposed for the wetlands identified within the transmission line corridor.

3.1 Additional Vegetation Maintenance Restrictions within and Adjacent to Freshwater Wetlands

Vegetation maintenance within, and within 25 feet of, freshwater wetlands with standing water will be conducted only by hand cutting with hand tools or chainsaws. Herbicide use is permitted in wetlands only when no standing water is present in the wetland at the time of the application. Herbicides will not be stored, mixed, transferred between containers, and no refueling of chain saws or other equipment will be allowed, within 100 feet of freshwater wetlands, unless done so on a public access road.

4.0 Vegetation Maintenance within Stream Buffers (Riparian Filter Areas)

A 75-foot buffer, as measured from the top of each stream bank, will be established for vegetation maintenance along perennial and intermittent streams not designated as coldwater fisheries, within the transmission line corridor. Additional restrictions will be applied within 100 feet of streams meeting certain criteria, as described below. Special restrictions will apply within these stream buffers during vegetation maintenance.

This section describes the additional restrictions related to vegetation cutting and maintenance within these stream buffers. All vegetation maintenance procedures and restrictions that apply to typical transmission line corridor maintenance also apply within stream buffers.

4.1 Additional Vegetation Maintenance Restrictions within Stream Buffers

The following additional restrictions apply to vegetation clearing within stream buffers:

a. Unless more restrictive requirements apply, riparian natural buffers (or “stream” buffers) will be retained within 100 feet of all streams (intermittent and perennial) in the GOM DPS , all perennial and coldwater fishery streams within Segment 1 of the Project and all coldwater fisheries in other segments, outstanding river segments, or rivers, streams, or brooks containing Threatened or Endangered species (e.g., Atlantic salmon) unless the Department determines that the functions and values of the stream buffer will not be impacted by the removal of vegetation and approves an alternative minimum buffer.
b. For streams in areas where the new transmission line will be co-located within existing rights-of-way, CMP proposes to maintain a 75-foot buffer, unless meeting any of the above criteria, since the existing corridor is currently being maintained in an early successional state according to the guidelines set forth in CMP’s Vegetation Management Plan (Exhibit D), and the effect of the additional clearing (typically less than 75 feet) to accommodate the new line has been minimized.
c. The boundary of each stream buffer will have unique flagging installed to distinguish between the applicable 75-foot or 100-foot stream buffer prior to clearing. Flagging will be maintained throughout construction.
d. Foliar herbicides will be prohibited within the stream buffer, and all refueling/maintenance of equipment will be excluded from the buffer unless it occurs on an existing paved road or if secondary containment is used with oversight from an environmental inspector.
e. All stream crossings by heavy equipment will be performed through the installation of equipment spans with no in-stream disturbances. Streams will not be forded by heavy equipment.
f. Initial tree clearing will be performed during frozen ground conditions whenever practicable, and if not practicable, the recommendations of the environmental inspector will be followed regarding the appropriate techniques to minimize disturbance such as the use of selectively placed travel lanes within the stream buffer. CMP will not place any transmission line structures within the stream

buffer, unless specifically authorized by the MDEP and accompanied by a site-specific erosion control plan. No structures will be placed within 25 feet of any stream regardless of its classification.

g. Within that portion of the stream buffer that is within the wire zone (i.e., within 15 feet, horizontally, of any conductor), all woody vegetation over 10 feet in height, whether capable or non-capable, will be cut back to ground level and resulting slash will be managed in accordance with Maine's Slash Law. No other vegetation, other than dead or hazard trees, will be removed. Within the stream buffer and outside of the wire zone, non-capable species may be allowed to exceed 10 feet in height unless it is determined that they may encroach into the conductor safety zone prior to the next four year maintenance cycle. Vegetation maintenance within Segment 1 will be on a two- to three-year cycle and must not exceed a three-year cycle within any particular area within this segment without prior approval from the Department. ;
h. Removal of capable species and dead or hazard trees within the appropriate stream buffer will typically be accomplished by hand-cutting. Use of mechanized harvesting equipment is allowed if supported by construction matting or during frozen conditions in a manner (i.e., use of travel lanes and reach-in techniques) that preserves non-capable vegetation less than 10 feet in height to the greatest extent practicable. Within the wire zone all woody vegetation may be cut to ground level;
i. No slash will be left within 50 feet of any stream; and,
j. Any construction access roads that must cross streams or brooks must be designed, constructed, and maintained to minimize erosion and sedimentation.

These additional restrictions will allow for taller vegetation within the appropriate stream buffer to provide shading and to reduce the warming effect of direct sunlight (insolation). Low ground cover vegetation will also remain to filter any sediment in surface runoff. The restrictions are also intended to minimize ground disturbance and prevent or minimize the surface transport of herbicides and petroleum products to streams. These restrictions will allow the stream buffers to provide functions and values similar to those provided prior to transmission line construction.

5.0 Vegetation Maintenance within Significant Vernal Pool Buffers

Vegetated buffers of 100 feet, as measured from the edge of the pool depression, will be established for SVPs crossed by the transmission line corridor. Vegetation maintenance within the SVP buffers will be subject to the same procedures and prohibitions, as applicable, that are required in the typical transmission line corridor, as well as to the additional measures below.

5.1 Additional Vegetation Maintenance Restrictions within Significant Vernal Pool Buffers

The following additional restrictions apply to vegetation maintenance within SVP buffers:

- Mechanized equipment will not be allowed within the vernal pool depression, unless the depression encompasses the entire width of the transmission line corridor. Mechanized equipment will only be allowed to cross the vernal pool depressions during frozen or dry conditions or with the use of mats;

- Between April 1 and June 30 in any calendar year, no vegetation maintenance using tracked or wheeled equipment will be performed within the 100-foot buffer. Maintenance will be performed using only hand tools during this period;
- Between April 1 and June 30 in any calendar year, no vegetation maintenance will occur within 25 feet of the SVP pool depression;
- No refueling or maintenance of equipment, including chainsaws, will occur within 100 feet of SVP pool depression, unless conducted on a public access road; and
- No herbicide use is permitted within 25 feet of the SVP pool depression.

6.0 Vegetation Maintenance within Moderate or High Value Inland Waterfowl and Wading Bird Habitat

Inland Waterfowl and Wading Bird Habitats (IWWH) are habitats mapped by the MDIFW that contain an inland wetland complex used by waterfowl and wading birds, plus a 250-foot nesting habitat area surrounding the wetland. The nesting habitat is considered to be part of the mapped IWWH. No additional buffers are proposed for IWWHs beyond this mapped habitat, and as such the vegetation maintenance restrictions apply to the mapped habitat only.

Vegetation maintenance within the IWWH will be subject to the same procedures and prohibitions, as applicable, that are required in the typical transmission line corridor and for stream buffers.

6.1 Additional Vegetation Maintenance Restrictions within Inland Waterfowl and Wading Bird Habitat

The following additional restrictions apply to vegetation maintenance within mapped IWWH:

- Between April 15 and July 15, use of motorized vehicles (e.g., all-terrain vehicles) and mechanized equipment (e.g., chainsaws or brush cutters) within IWWH is prohibited. Use of non-mechanized hand tools is allowed during this time period;
- No refueling or maintenance of equipment, including chainsaws, will occur within the IWWH, unless done so on a public access road;
- No herbicide use is permitted within 25 feet of any wetland within the mapped IWWH; and
- Provided they do not pose a safety hazard, naturally occurring snags within IWWH will be allowed to remain, at a minimum of two to three snags per acre.

7.0 Vegetation Maintenance within Mapped Deer Wintering Areas

Deer Wintering Areas (DWA) provide important refuge for white-tailed deer (*Odocoileus virginianus*) during the winter months in northern climates and are typically characterized by an extensive stand of mature softwood species with a dense forest canopy.

No additional vegetation maintenance restrictions are proposed within mapped DWAs, as all capable species must be removed from these and other areas within the transmission line corridor in order to comply with NERC Transmission Vegetation Management standards.

8.0 Vegetation Maintenance within Rare Plant Locations

Vegetation maintenance of the transmission line corridor has the potential to impact rare plants and/or alter their habitat. The following additional vegetative maintenance restrictions will minimize such impacts. The additional restrictions will apply only to the demarcated locations of the identified rare plants. No additional buffers will be established surrounding rare plant locations. These restrictions are intended to maintain existing hydrology and limit soil disturbance within rare plant locations.

8.1 Additional Vegetation Maintenance Restrictions within Rare Plant Locations

The following additional restrictions will apply to vegetation maintenance for the rare plant occurrences in the Project area:

- All capable tree species will be cut by hand (chainsaws, hand saws or axes). No other mechanized cutting equipment shall be used within these habitats;
- Unless rare plant locations encompass the entire width of the transmission line corridor, mechanized equipment will only be allowed to cross rare plant locations during frozen conditions or with the use of mats;
- No refueling or maintenance of equipment, including chainsaws, will occur within demarcated rare plant locations, unless done on a public access road; and
- No foliar herbicide use is permitted within the demarcated rare plant locations, however cut surface herbicides may be used on capable species and specimens.
- Crossing of rare plant locations with mechanized equipment:

  <u>All-Terrain Vehicles (ATVs)</u>

  - Due to small footprint, relatively light weight, and infrequency of use, ATV impact is minimal, therefore crane mats will not be used.
  - If rare plants do not encompass entire ROW width, ATVs will avoid/travel around rare plants.
  - If rare plants encompass entire ROW width:
    - ATVs will utilize existing rare plant travel path/crossing if one exists.

- If no rare plant crossing exists, ATVs will cross at narrowest point of the rare plants and will restrict this crossing to a single travel lane.

Heavy Equipment/Vehicles

- During emergency repair & maintenance work, crane mats will not be used. Heavy equipment/vehicles will utilize existing rare plant crossings if available.
- During planned repair & maintenance work:
    - If rare plants do not encompass entire ROW width, heavy equipment/vehicles will avoid/travel around rare plants. Crane mats will not be used.
    - If rare plants encompass entire ROW width, and there is an established travel path/crossing through the rare plants, heavy equipment/vehicles will utilize this crossing, and crane mats will not be used.
    - If rare plants encompass entire ROW width, but there is no established travel path through the rare plants, heavy equipment/vehicles will cross rare plants using crane mats.

9.0 Maintenance Procedures for Mapped Significant Sand and Gravel Aquifers

Transmission lines located over mapped significant sand and gravel aquifers are subject to the typical transmission line corridor maintenance procedures, except that no refueling or maintenance of equipment, and no herbicides may be mixed, transferred or stored, over the mapped significant sand and gravel aquifers, unless done so on a public access road.

10.0 Locating and Marking Buffers and Habitats

A database will be maintained, including maps and GIS shapefiles, of the buffers, restricted habitats, and sensitive areas and their locations relative to the nearest structure (pole) or road location. The distance and direction from the nearest structure to the sensitive area will be included with the name of the area and the structure number. All structures along the transmission line corridor will be numbered at the time of construction.

To aid in identifying restricted areas, buffers and restricted habitats may be located and demarcated in the field using brightly colored flagging or signage prior to the initiation of maintenance activities along the transmission line corridor. Alternatively, use of GIS data and GPS equipment may be used to provide accurate location of resources and associated buffers during maintenance activities. If desired, maintenance personnel may permanently demarcate restricted habitats to aid in long-term maintenance activities. Maintenance contractors working on the transmission line corridor will be provided a copy of this VMP. Use of this VMP in conjunction with the As-Built Plan & Profile drawings will enable maintenance contractors to locate and mark restricted areas in the field.

11.0 Maintenance Personnel Training

Personnel who will conduct vegetation maintenance activities on the transmission line corridor will receive appropriate environmental training before being allowed access to the transmission line corridor. Maintenance personnel will be required to review this VMP prior to the training and before conducting any maintenance activities. The level of training will be dependent on the duties of the personnel. The training will be given prior to the start of maintenance activities. Replacement or new maintenance personnel that did not receive the initial training will receive similar training prior to performing any maintenance activities on the transmission line corridor.

The training session will consist of a review of the buffers and restricted habitats, the respective maintenance requirements and restrictions for each, and a review of how these areas and resources can be located in the field. Training will include familiarization with and use of GIS information and sensitive natural resource identification in conjunction with the contents of this VMP, as well as basic causes, preventive and remedial measures for contamination, and erosion and sedimentation of water resources. Training will also include a review of safety and the proper use of appropriate maintenance tools.

EXHIBIT 7 ENVIRONMENTAL GUIDELINES FOR CONSTRUCTION AND MAINTENANCE ACTIVITIES ON TRANSMISSION LINE AND SUBSTATION PROJECTS

Environmental Guidelines For Construction and Maintenance Activities on Transmission Line And Substation Projects

Prepared for:

Central Maine Power Company
83 Edison Drive
Augusta, Maine 04336

Prepared by:

TRC Engineering, LLC
249 Western Avenue
Augusta, Maine 04330

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4	Various	Consistency with latest MDEP BMPs	G. Mirabile	June 2018

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CENTRAL MAINE POWER COMPANY

Environmental Guidelines for Construction and Maintenance Activities on Transmission Line and Substation Projects

1.0 INTRODUCTION

These guidelines contain standards and methods used to protect soil and water resources during construction, reconstruction, and maintenance of transmission lines and substations. They are based on practical methods developed for construction in utility corridors and their use is enforced by both State of Maine and Federal regulatory agencies. The construction practices described in this manual are typically required by the regulatory agencies for all projects. These practices are commonly referred to as Best Management Practices (BMPs). Illustrations have been provided as part of this manual (Appendix D) which demonstrate both the proper and improper techniques used for the more common construction activities.

All contracts for work performed on Central Maine Power Company (CMP) transmission line rights-of-way and substation sites will include these specific guidelines to ensure the project is constructed in an environmentally conscious manner. CMP personnel or their designated representatives will ensure that the guidelines are followed by inspecting all work and prescribing corrective steps to be taken where necessary. While this manual takes into consideration legal requirements, project personnel are still responsible for compliance with all federal, state, and local requirements.

This guide uses a number of scientific and technical terms. Definitions of these terms are provided in Appendix A.

2.0 PLANNING AND DESIGN CONSIDERATIONS

Planning is an important practice that will reduce the risk of erosion on a construction site, saving both time and money for Central Maine Power Company and its contractors. An erosion control plan should be prepared during project planning and design phases. It will likely be required for any Maine Department of Environmental Protection and/or local permits.

The erosion control plan should consist of:

- A narrative.
- A map.
- Plan details.

The narrative should describe the proposed project, existing site conditions, adjacent land uses, and any natural resources or properties that might be affected by the project. Other important details to include are descriptions of critical areas, proposed construction start and end dates, construction sequence, and brief descriptions of erosion and sedimentation control measures, inspections and maintenance programs, and other clearing or construction that has taken place on the site in the last five years.

The map should include pre-development site contours at a scale to identify runoff patterns (minimum 5-foot contour interval), final contours, limits of clearing and grading, existing buffers, critical areas, natural resources, erosion control measures, and other clearing or construction that has taken place on the site in the last five years.

The plan details should include drawing of the erosion control structures and measures, design criteria and calculations, seeding specifications, and inspection and maintenance notes.

Key considerations include resource identification, familiarizing all parties with the construction site and limitations, and construction sequence.

2.1 Resource Identification

Sensitive natural areas which will receive priority treatment include:

- Streams and rivers.
- Great ponds.
- Wetlands.
- Steep slopes.
- Unstable soil conditions.

Sensitive natural areas which may receive priority treatment, depending upon the specifics of the project, include:

- Stream, river, pond, and wetland buffers.
- Significant wildlife habitats.
- Habitat for rare species.
- Historic and prehistoric sites.

During the planning phase, all sensitive natural areas that require priority treatment will be identified. The method of avoiding or crossing the sensitive natural areas to minimize impacts will be identified and incorporated into the project plans. Project plans should be designed and drawn to provide contractors and inspectors with a comprehensive reference guide that include, but is not limited to, locations of sensitive natural areas, access, and abutter and landowner issues. If modifications to the plans need to be made in the field, a designated person shall make necessary changes and shall notify all necessary personnel promptly. Copies of these plans should be provided and explained to equipment operators to assure that construction practices meet the intent of avoiding or minimizing impacts to the identified sensitive natural areas. In addition to the plans, the proposed access ways and water/wetland crossing locations, as well as other environmentally sensitive areas where activities will be restricted or prohibited, will be flagged and/or have signs posted.

Prior to crossings or construction in or near any sensitive natural areas, a "walk-through" will be conducted. Attendees at the walk-through will include: 1) the contractor, 2) CMP and/or any designated representative, and may include 3) any assigned Third Party Inspector. The purpose of the walk-through is to establish the following objectives, **prior to any clearing or construction work**:

- Identify available or alternate points of access to the project site.
- Identify sensitive natural areas.
- Identify future "No-Access" areas.
- Review color designation for all flagging used.
- Establish the Communication Chain of Command (Contact Point).
- Identify and flag access/construction roads within the ROW and/or project area.
- Establish methods of access over water resource areas (mats, timber corduroy, frozen ground, tracked equipment).

In order to minimize impacts to sensitive natural areas, the above objectives will continually be evaluated throughout the construction process. Project superintendents, foremen, and inspectors should also monitor weather conditions and reports on an on-going basis. Knowledge of changing or anticipated wet weather will allow time to address erosion control needs. In this way, CMP and its contractors will be prepared to respond to changing environmental conditions (e.g., unusually wet or dry weather) and other unknowns that are inherent in the construction and maintenance of transmission lines.

2.2 "Walk-Through" Mechanics

2.2.1 Use of Flagging and Signs

Flagging will be conducted at the time of the walk-through in order to visually identify select features or construction methods to be used. Wetlands may be flagged earlier as part of project permitting. Signs may also be installed following the walk-through to direct construction to approved access routes and away from "no access" areas. The CMP flagging color-code is as follows:

- ***Glow-pink*** with the printed words "Wetland Delineation", "Wetland Boundary" or "Wetlands". This flagging denotes the edge of wetlands.
- ***Red*** with or without the printed words – "Do Not Cross". This flagging denotes a No-Access area where no equipment is allowed.
- ***Yellow*** – no printed words. This flagging denotes the location of an environmental measure such as a waterbar, hay bale barrier, or silt fence.
- ***Blue*** – no printed words. This flagging denotes approved travel ways. This is typically flagged on each side of the access-way to denote the designated travel lane for all access.
- ***Glow-pink with black stripes*** or otherwise printed with the words Buffer or Wetland Buffer. This denotes a setback from a water resource and should be treated the same as No-Access area.

2.2.2 Identification and Use of Existing Roads

Available logging, farm, or access roads, as well as other existing rights-of-way, will be utilized for access to and from transmission line rights-of-way with permission of the respective landowners. In order to minimize ground disturbance, existing roads within the right-of-way and wetland/stream crossing areas will be used whenever possible for travel during construction, unless a better route is agreed upon during the walk-through. The movement of equipment and materials within the transmission line right-of-way will be confined as much as possible to a single road or travel path.

For example, it may be better to construct new access roads in order to: (1) minimize the span of a wetland or stream crossing, or (2) avoid the more environmentally sensitive or "wetter" portions of a wetland or stream crossing.

In all cases, CMP and its contractors will attempt to avoid and minimize impacts to sensitive natural areas. As a result of this procedure, wetland and stream crossings, steep slopes, unstable soils, and other sensitive natural areas will be avoided and adverse impacts minimized whenever practicable.

2.3 Construction Sequencing

Although a "Project Plan" may be specific in identifying the *locations* of water resource areas (wetlands, streams, etc.), and the *methods* of access over water resource areas (crane mats, frozen ground, etc.) it should not dictate *when* construction activities should occur. It would be impractical to include day to day activities in the "Project Plan" such as, 'pole X will be installed on Y date'. However, including environmental considerations in the daily and weekly project planning is very important. Factors such as the project schedule and weather often determine where and when construction activities occur; environmental impacts should also be considered. Below are some guidelines:

- Work closely with the individual(s) in charge of environmental compliance to plan project activities.
- Construction activities that cause soil disturbance should not occur during or just prior to forecast heavy rain events.
- Coordinate access planning with all of the contractors on the project. Often temporary access roads are used by several different contractors and the construction and use of temporary access roads can cause significant soil disturbance. Minimize equipment and vehicle travel on temporary access ways.
- Stabilize/restore disturbed areas as soon as possible, preferably while equipment is on site. Additional trips with equipment can create more soil disturbance which will need to be stabilized. Often a site can and should be stabilized within hours of when the soil disturbance occurred.
- Use frozen conditions to your advantage. There may be instances where water resource areas can be crossed during frozen conditions in lieu of installing crane mats. Before using this technique consult with the project environmental inspector.

- Crane mats should be removed as soon as they are no longer needed and/or when conditions are favorable.

3.0 STANDARDS FOR CONSTRUCTION

3.1 Road Construction

The following five standards apply to the construction and/or upgrade of all roads, skid trails, yarding areas, or work pads whether temporary or permanent.

1. Where construction will be located near water resources, such that material or soil may be washed into them, these disturbances will be set back from the edge of the water resource to maximize the amount of undisturbed filtering area between the disturbed area and the resource. These "filter strips" will consist of an area of undisturbed vegetation between the edge of disturbed area and/or silt fence/hay bale barriers placed to intercept any sediment load in runoff water before it can enter the resource area. In order to maintain the integrity and effectiveness of filter strips, sediment barriers should be installed very early in the construction sequence, and they need to be monitored to make sure they are functional. Effective filter strip widths may vary from only a few feet in relatively well drained flat areas to as much as several hundred feet in steeper areas with more impermeable soils. In steep terrain, additional erosion and sedimentation control measures will be installed at the low point where the work area drains into the filter strip when exposed soils exist and the flow path may result in channelization of runoff. The minimum width of the buffer strip shall be 25 feet or in accordance with local CEO or DEP regulations. The width of the filter strip shall be increased proportionately for slopes longer than 150 feet or for higher sediment concentrations. **Table 1** below provides the recommended widths for the filter strips according to the slope of land between the edge of the resource and any exposed soil.

Table 1
Recommended Widths For Filter Strips Between Disturbed Areas And Water Resources

Slope of Land Between Disturbance and the Resource (Percent)	Width of Filter Strip* (Feet)
0	25
10	45
20	65
30	85
40	105
50	125
60	145
70	165

*Measured along surface of the ground

2. Wherever possible, construction equipment will either avoid steep slopes or proceed across the slope in a safe manner to avoid excessive disturbance of vegetation and soils. Equipment will not travel straight up or down any slopes with a grade steeper than 10 percent, except where necessary due to safety concerns and/or terrain constraints.
3. Where access roads or construction areas are to be built across the slope, the area will be properly sloped, slanting away from the cut bank to the outside edge of the roadbed in order to facilitate road surface drainage.
4. Slopes of cut-and-fill banks will be no steeper than 1 horizontal to 1 vertical. If located within 100 feet of water resources, the slopes will be no steeper than 2 horizontal to 1 vertical.
5. Rivers, streams, and wetland areas will be crossed, where necessary, at right angles to the channel and/or at points of minimum impact. To insure that natural drainage patterns will not be altered or restricted as a result of construction activities, crossings will be designed and constructed according to specific standards outlined below.

3.2 Stream or Wetland Crossings

The following standards apply to all unavoidable stream, drainage way, or wetland crossings encountered while accessing the project site or on the project site itself.

3.2.1 Types of Crossings Used

The type of crossing used for access is dependent on: the purpose and use of the crossing, the nature of the resource being crossed, ground conditions present at the time of construction, and construction materials available. Some planning guidance is provided below. The appropriate means and location of the crossing will be determined at the time of the formal walk-through. It is important to consult with the project environmental inspector prior to installing any crossing.

- Permanent culverts and bridges will be used only where long-term, continued, and frequent access is required (such as substation access roads).
- Temporary crossings will be used at all other locations. Temporary bridges, culverts, or crane mats must be used to cross any streams, drainage ways, or wetland swales that contain: (1) flowing water, (2) standing water, (3) saturated soils, or (4) organic/mucky soils.
- The use of corduroy as crossing material will be limited to wetlands which are not anticipated to have flowing or standing water during the construction period.
- In certain cases, no crossing material will be required if the stream bottom or drainage way is dry and contains a gravel or solid rock bottom (a “ford”). Fords can only be used if they will cause no unreasonable sedimentation of the stream and no unreasonable alteration of the stream banks and bottom.
- All crossings should include water bars or broad based dips or turn outs on the access, appropriately spaced on each side of the crossing, to promote filter-strip treatment of runoff. Consult Table 4 on page 12 of this document for specific water diversion structure spacing standards.
- All temporary crossings must be stabilized within seven (7) days of its removal, unless specified otherwise.

3.3 Construction in Wetlands

Where structures are to be placed in wetlands, topsoil must be excavated first, and stockpiled separate from subsoil. Be sure that stockpile soils are placed in such a manner that they are readily replaced into the excavated area. Soils shall be replaced into the excavated area in the opposite order they were removed. Excavation and pole placement in wetland areas should be completed within the same day. After pole installation, topsoil must be restored to the original surface grade, except where mounding around a structure is necessary for structure stability.

4.0 INSTALLATION OF CROSSINGS

4.1 Bridges

Bridges are a preferred method for temporary access waterway crossings. Normally, bridge construction causes the least disturbance to the waterway bed and banks when compared to the other waterway crossing methods. Most bridges can be quickly removed and reused without significantly affecting the stream or its banks and without interfering with fish migration.

<u>Materials</u>
Access bridge construction typically entails the use of log stringers as construction materials.

<u>Sizing</u>
Table 2 below illustrates the log sizing requirements depending on the span and anticipated loads.

Table 2
Log Bridge Stringer Requirements

Span	Minimum Log Diameter* (80,000 lb. Load)	Minimum Log Diameter* (40,000 lb. Load)
8 ft.	16 in.	12 in.
12 ft.	18 in.	14 in.
16 ft.	20 in.	16 in.

Wheel guards: 10” diameter
- Size of deck planks: 4” x 12” x 12’
* Assume 6 stringers at 24” centers

<u>Positioning</u>
The following is guidance for the positioning and installation for all permanent and temporary bridges:

- Access roads will cross streams at right angles to the channel at a location with firm banks and level approaches whenever possible.
- Bridge piers and abutments will be aligned parallel to the stream flow so that the original direction of stream flow is not altered.
- Piers and abutments will be imbedded in good foundation material. The grade of the bridge should coincide with that of the road wherever practicable.

For additional specifications on bridge construction, refer to section F-2 of the Maine Erosion and Sediment Control BMPs (see full citation in Appendix C).

4.2 Culverts

Materials

Permanent culverts will be either corrugated metal or plastic pipe. Temporary culverts will be corrugated metal, plastic pipe, or lumber ties. Chemically-treated wood will be not used.

Sizing

Permanent culverts will be sized to have a diameter of at least 3 times the cross-sectional area of the stream channel or will be designed to accommodate 25-year frequency flows. Multiple culverts may be used in place of one large culvert if they have the equivalent capacity of a larger one. A culvert sizing criteria table (3x Rule) produced by the MDEP can be found in Appendix G. However, it is recommended that an engineer be consulted when installing any permanent culvert.

Temporary culverts will also be sized to provide an opening at least 3 times the cross-sectional area of the stream channel and sized to accommodate a 25-year frequency storm flow. The stream channel cross-section will be determined at highest flows or will be approximated during periods of lower flows using the apparent natural high water marks remaining on the stream banks. For small intermittent streams, drainage ways or wetland crossings, the minimum sized culvert that may be used is 18 inches. Multiple culverts may be used in place of one larger culvert if they have the equivalent capacity of a larger one.

Positioning

The following is guidance for the positioning of all permanent and temporary culverts:

- Culverts should be placed to allow for the crossing to take place at right angles to the channel to assure that natural drainage patterns will not be altered.
- Culverts should be placed at the point of narrowest crossing and where firm banks and level approach slopes are available. Slopes should be no greater than 1.5 to 1.

Installation

The following is guidance for the installation of all permanent and temporary culverts:

- Culverts should be of sufficient length to allow both ends to extend at least one foot beyond the toe of any fill used to cover the culvert.
- Inlet and outlet armoring shall extend at least one pipe diameter beyond the upstream and downstream end of the culvert. See Table 3 below for outlet protection in erodible areas.
- Culverts should be bedded on firm ground. Supplemental use of geotextile with gravel can be used to create this firm base. Permanent culvert installation should include firm compaction of the foundation and the fill around the sides of the culvert. Compaction should be done in no more than 8-inch lifts.

- Both the inlet and outlet ends of the culverts will be set at or slightly below the natural stream bottom to allow passage of fish and other aquatic life at all levels of flow. At no point should either end of an installed culvert be positioned in the air out of the water.
- Multiple culverts must be offset in order to concentrate low flows into the culvert within the natural channel.
- When working in and around a perennial stream, temporary stream diversion may be necessary to avoid creating turbidity in the stream water. This type of work requires a permit from Maine DEP, and must be coordinated with the project environmental inspector.
- Fill used to bury the culvert will be compacted at least half-way up the side of the culvert for its full length in insure that flowing water will not undermine the culvert.
- Culverts will be covered with fill to a depth of at least one foot or one and a half times the culvert diameter, whichever is greater.
- Road fill at the upstream (headwall) and downstream (out-fall) ends of culverts will be armored with either rock rip rap or logs to protect the road fill from being eroded by the action of water or road traffic. This material will be installed up to the level of anticipated high water.
- In areas where the streambed appears highly erodible, the streambed at the outlet end of the culvert will be lined with riprap to prevent erosion and potential stream bed scour. Table 3 below indicates the distances away from the culvert to install such riprap.

Table 3
Culvert Size - Length of Rock Protection

Culvert Diameter (Inches)	Length of Rock Protection From Culvert (Feet)
12 – 20	7
21 – 24	9
30	11
36	13
42 – 48	18
54 – 60	24
66 – 78	32

<u>Removal</u>
Temporary culverts will be removed once their use is no longer necessary. The fill material can be redistributed and spread out on the nearby uplands at a distance sufficient to prevent its reentry into the resource. Silt fence/hay bales, seeding, and mulching may be necessary to stabilize this material. The banks and bottoms of the stream, drainage way, or wetland should be restored to original conditions. Exposed soils on the banks and within 100 feet of the crossing should be stabilized using seed and mulch. Some banks and steep slopes adjacent to streams may require stabilization with curlex or jute matting in combination with seed and mulch.

4.3 Mats (Crane or Swamp Mats)

CMP construction projects require that adequate mats are present at the project site prior to construction. A readily accessible source of mats should also be available in case construction conditions change and necessitate the need for more mats.

Materials

A number of different sized and constructed crane mats are typically available. CMP requires that the appropriate mats be used for the appropriate crossing. For example:

- Longer mats should be used for the longer crossing spans. This practice avoids the need to install additional mats within the crossing area in order to support the “span” mats.
- Mats should be in good condition to allow for their “clean” installation. Having mats in good condition prevents them from being dragged in versus them being carried in due to broken hitching cables, breaking apart on the job site, or becoming imbedded in mud due to their inability to support the required weight.
- Mats with partial/short timbers joined end to end should generally not be used to cross stream channels.

Installation

- Whenever possible, mats should be carried and not dragged. Dragging mats creates more soil disturbance which requires additional erosion control or final restoration work.
- At the crossing location, the ends of the crane mats should extend at least two feet onto firm banks or several feet into the upland edge of a wetland to assure a dry, firm approach onto the mats.
- At crossings which contain open or flowing water, the mats should be supported within the span using cross mats as abutments in order to prevent the impoundment of water or having water flow over the mats.
- At “dry” crossings where no water is present or anticipated during project construction, the mats may be placed directly onto the sensitive natural area in order to prevent excessive rutting, provided stream banks and bottoms are not altered.

Maintenance

Matted crossings should be continually monitored to assure their correct functioning. Mats which become covered with dirt should be kept clean and the material removed must be disposed of in an upland location. The material must not be scraped and shoveled into the water resource. Mats which become imbedded must be reset or layered to prevent mud from covering them or water passing over them.

Removal

Mats should not be removed until their use is absolutely no longer necessary. Specifically, all final restoration work should be completed prior to the mats being removed from the crossings. The planned removal of mats should be coordinated with CMP (or designated representative), the project environmental inspector, and any Third Party Inspector. As temporary structures, they should be removed within one year from the date of installation. All areas disturbed during ford removal shall be stabilized with seed and mulch.

4.4 Corduroy

Materials

Corduroy material will consist of de-limbed trees or logs. The logs must have a diameter greater than three inches at the small end and lengths greater than 18 feet. Shorter length material may be used only as described in the Installation section below.

Positioning

Corduroy should be placed perpendicular to the direction of travel. Corduroy should be placed at the point of narrowest crossing and where firm banks and level approach slopes are available.

Installation

The corduroy should be placed with the longer length pieces laid down first. The bed of corduroy should not only be placed within the low portions of the crossing but also for at least three feet up the sides of any upland side slopes in order to prevent rutting and sedimentation from the approaches to the crossing.

Once a thick base of corduroy has been laid, pieces shorter than 18 feet can be used to fill gaps and raise the elevation of the corduroy to provide for a more stable crossing.

Removal

Removal is the reverse of installation. Once the corduroy has been removed from the crossing, it may be moved off the right-of-way, burned, or chipped. The material may also be spread and distributed on the ROW over the nearby upland if in accordance with the Maine Slash Law (see Appendix E) and approved by a CMP representative. The banks of streams and drainage ways must be graded back to original conditions. Exposed soils on the banks and within 100 feet of the crossing must be stabilized using seed and mulch. Banks of drainage ways that are expected to receive high flows should be stabilized with seed and curlex or jute matting.

5.0 SURFACE WATER DIVERSION STRUCTURES (WATER BARS)

A number of above-ground structures or techniques are available to divert water out of travel ways and work areas in order to prevent subsequent runoff and erosion. The terminology and definitions for these techniques (i.e., broad-based dips, water bars, skid humps, water turnouts, and cross-drainage box culvert) vary, but the purpose of all is to redirect water moving down a slope into adjacent vegetated areas (filter strips). Any activities that involve land grading have the potential to cause sedimentation. Their use and installation needs to be carefully planned. Planning for these techniques must include timing, use of natural buffers (filter strips), mulching, and temporary and permanent seeding. Minimizing the area of soil exposed at one time is a key component of ensuring that surface water diversion structures function effectively. General standards for their construction are as follows.

Materials

Most of these structures are constructed by excavating or moving and shaping earth from within the access way or work area. The cross-drainage culvert structure typically uses logs or timber to form a box-like structure to catch water from travel ways or side ditches in order to direct it across the travel way and away from disturbed areas.

Positioning

These structures should be installed immediately above and along steep pitches in the road and below seepage areas on natural or cut banks; be sloped away from the travel surface and be sited to take advantage of existing vegetation for filtering. In some areas of exposed soils, the right-of-way might be sloped such that runoff traverses the disturbed area. In these areas, temporary water diversions should be deployed to divert the upgradient runoff away from the disturbed work area and towards a stable drainageway. The interval for installing these diversion structures depends on the slope of the road, as well as the nature of the road surface, soils, and wetness. Generally speaking, steeper slopes require shorter distances between diversion structures. The following table contains recommended distances between installed structures depending on slope.

Table 4
Recommended Distances Between Water Diversion Structures

Slope (Percent)	Spacing (Feet)
2	250
5	135
10	80
15	60
20	45
30	35

All of these structures should be sized in anticipation of greater flows resulting from snow melt, spring runoff, and storm rains.

Installation

These structures should be installed at 30-degrees angled down grade. The shape of the backside portion of the structure should have a reverse slope of about 3 percent. Use of a pop-level is recommended to ensure that drainage is away from the road. Structures should be constructed with rounded (not vertical) mounds and dips to allow for firm compaction and to allow re-vegetation.

In the case of the cross-drainage culvert, the minimum width of the open face of the culvert should be 18 inches. The travel surface should consist of at least 12 inches of gravel or soil over the culvert. The slope of the culvert should be a drop of at least 5 inches in every 10 feet of length to ensure proper drainage.

The inlet end of all structures should extend beyond the edge of the access road so that it fully intercepts water flows that may flow onto the access road. The outlet end of the structure should extend out enough to prevent water from flowing around and re-entering the road or work area.

The discharge ends of any of these diversion structures should outlet into a vegetated filter strip. Where heavy flows are encountered or anticipated, the outlet end of the structures should incorporate an apron of rock, gravel, or brush to reduce water velocities. If construction will extend into fall and winter months, be sure to upgrade to meet winter standards all erosion control measures (e.g., increase amount of mulch, etc.), to protect the site from spring runoff.

Where the structure is within 100 feet of a stream or wetland, the incorporation of a small, excavated settling basin or ditch turnout to reduce the velocity of flows and the continued movement of sediment downslope should be considered. In addition, some type of sediment barrier (silt fencing or staked hay bales) will be installed at the outlet of the diversion structure, where vegetated filter strips are narrow or sparsely vegetated, in order to prevent sediment from eroding into water resources.

Maintenance
Due to repeated travel over these structures, maintenance is critical to their effective functioning. As the structure becomes flattened or rutted, it needs to be re-excavated or graded to ensure the interception and redirection of water runoff. The ends of any cross-drainage culverts should be maintained by clearing away any potential blockages.

Removal
After the completion of the construction project, removal of these structures is not a requirement, with the exception of the cross-drainage culvert. The structures can be left in place provided they have been suitably stabilized with seed and mulch. Any hay bale barriers or silt fence at the outlet end should be removed when the site has a healthy vegetative cover.

6.0 SEDIMENT BARRIERS (STRUCTURAL MEASURES)

6.1 Introduction

The use of properly installed erosion and sediment control barriers is a fundamental and critical component for preventing erosion at CMP construction projects. Erosion control barriers include silt fence, hay bales, and/or erosion control mix berms. In some cases, these barriers may be deemed unnecessary by CMP, its representatives, or a Third Party Inspector due to factors including slope and filter strip width within project boundaries. A typical CMP construction project will use a combination of barriers to effectively control erosion near water resources. Installation and diligent maintenance of these barriers serves the following purposes:

- Assures the environmental integrity of those upland and water resource areas not designated or permitted for disturbance. Specifically, it maintains the onsite vegetative community and water quality of the surface water within the watershed.
- Assures compliance with all applicable federal, state, and local environmental and land use regulations or permit conditions.

Generally, silt fence is the preferred barrier because: it traps a much higher percentage of suspended sediments than hay bales; it can be easier to install, obtain, and transport; and is less costly. In addition, the structural longevity of silt fence is 60 days or longer unlike straw or hay bales' longevity which is 60 days or less.

The standards and procedures outlined in this section of the manual are meant to address a majority of the situations encountered during transmission line and substation construction activities. For additional information on sediment and erosion control methods and techniques, or to address a particularly problematic situation, this manual should be used in conjunction with and supplemented by the Maine Erosion and Sediment Control BMPs. For other recommended references, see Appendix C.

6.2 Silt Fence

Materials
Silt fence is provided by a number of manufacturers and is generally a synthetic fabric pre-attached to wooden staking. The fabric should be pervious to water allowing a flow through rate of 0.3 gallon per square foot per minute. The fabric should contain stabilizers and ultraviolet ray inhibitors to allow it to sustain exposure of a minimum of 6 months. The height of the filter fabric should not exceed 4 feet in height.

Placement
Silt fence is to be utilized at the edge of any planned work area or area which will cause the disturbance of soil. It will be installed to intercept any sheet flow of water and detain sediment from entering water resources or leaving the project site. It should be installed prior to starting work. Given the expansiveness of CMP transmission line projects in particular, the amount of silt fence placement must be selective; however, it should still be used in amounts sufficient to meet potential changing conditions in a pro-active manner. After the primary stabilization measures (temporary and permanent) have been implemented, silt fence use is encouraged in the following selected locations, as appropriate:

- Around all substation project sites.
- Along all access roads or work areas that are within 100 feet of water resources.
- Along all access roads or work areas in upland settings that encounter seepage moving across slope.
- Around all stockpiled soils.

In general, the placement of silt fence is appropriate when:

- Serving a drainage area of no more than .25 acre per 100 feet of silt fence length.
- The maximum slope length behind the fence is 100 feet or less.
- The maximum gradient behind the fence is 50% or 2:1 horizontal/vertical.
- Where the filter strip is not of an adequate width (see Table 1).

Installation
The following installation guidelines are the minimum which should be implemented; however, appropriate changes to silt fence installation should be made as conditions change during the construction operation.

Silt fence will be placed an adequate distance (6-10 feet) beyond the toe of the slope (if there is sufficient room) to allow for sediment accumulation between the disturbed area and the down-gradient water resources. If there is not sufficient room to place the silt fence an adequate distance beyond the toe of the slope, CMP, a representative of CMP, or the Third Party Inspector should be consulted. The barrier should be installed along the contour, within reason. The goal is to slow and pool the sediment-laden runoff to allow fine sediments to settle-out before the runoff enters the water resource. The ends of the barrier should be up-turned to maintain the pool volume.

A trench shall be excavated approximately 6 inches wide and 6 inches deep on the up-slope side of the silt fence alignment. The lower edge of the silt fence fabric should be entrenched for a distance of at least 4 inches up-slope and then back-filled. Should frozen or rocky ground conditions prevent the effective or practical use of trenching, materials such as bark/wood chips, wood fiber mulch, or a soil erosion control mixture can be used. This material is to be mounded on top of at least 4 inches of filter fabric which would otherwise be trenched.
Silt fence should be installed in a continuous roll to avoid the need of a joint between different pieces of fence. If joints are necessary, filter fabric shall be "spliced" together at a support post, securely sealed, and with a minimum of 6 inches of overlap. Splicing rolls of silt fence entails twisting end posts together, creating a continuous section of silt fence.

Support posts should be placed on the down-slope side or the side closest to or facing the water resource. The posts should be placed 6 feet apart (a maximum of 10 feet may be acceptable in some locations) and driven securely into the ground, typically about one foot deep. Silt fence usually has posts pre-attached.

Silt fence should not be installed in streams or drainage ways where concentrated water flow is present or concentrated flows are anticipated.

<u>Maintenance</u>
Once a week, or after rainstorms producing at least ½ inch of rainfall, whichever is more frequent, the contractor is responsible for inspecting all temporary erosion and sediment control barriers. Such inspection is necessary to assure that the barriers are functioning properly as well as identifying new areas requiring installation. A maintenance log should be kept of all erosion control changes, improvements, and maintenance performed.

If any barriers are not functioning properly, they will be repaired or replaced. A sediment control barrier is not functioning if:

1. Water is flowing around the sides or under the barrier.
2. Soil has built up behind the barrier to the point more than half-way up the fence.
3. There is excessive sag in the fence.
4. There is evidence of sedimentation such as gully erosion, slumping of banks, or the discoloration of water outside of the perimeter silt fence.

Corrective measures include removing accumulated sediment from behind the barrier, restaking, extending the ends of the fence, or installing another fence further upslope.

Removal
Installed silt fence will be removed once it is evident that the soils have become stabilized and the potential for erosion no longer exists. In most cases, the silt fence will not be removed until at least one growing season has past. Removal of silt fence should be coordinated with CMP or their designated representative.

Any ridges or mounds of soil or caught sediment remaining in place after the silt fence has been removed, must be leveled-off to conform to the existing grade. Any newly exposed soil that may erode must be seeded and mulched.
All removed silt fence must be properly disposed of off the project area.

6.3 Hay Bales

Placement
Like silt fence, hay bale barriers can be utilized at the edge of any planned work area or areas where soil disturbance has occurred or will occur. Barriers are installed to intercept sheet flow of water and detain sediment from entering water resources or leaving the project site. Given the expansiveness of CMP transmission line projects in particular, the amount of hay bale barrier placement must be selective, but still in amounts sufficient to meet potential changing conditions in a pro-active manner. Hay bale barriers will be used, as appropriate, in the following locations:

- Around all substation project sites.
- Along all access roads or work areas that are within 100 feet of a water resource area.
- Along all access roads or work areas in upland settings that encounter seepage moving across slope.
- Around all stockpiled soils.

In general, the placement of hay bales is appropriate when:

- Serving a drainage area of no more than .25 acre per 100 feet of barrier length.
- The maximum slope length behind the barrier is 100 feet or less.
- The maximum gradient behind the barrier of 50% or 2:1 horizontal/vertical.
- Where the filter strip is not of an adequate width (see Table 1).

Installation
The following installation guidelines are the minimum which should be implemented; however, appropriate changes to hay bale installation should be made as conditions change during the construction operation.

The barrier will be placed an adequate distance (6-10 feet) beyond the toe of the slope (if there is sufficient room) to allow for sediment accumulation between the disturbed area and the down-gradient sensitive areas. If there is not sufficient room to place the hay bales an adequate distance beyond the toe of the slope, CMP, a representative of CMP, the project environmental inspector, or the Third Party Inspector should be consulted. Within reason, the barrier should be installed along the contour. The goal is to slow and pool the sediment-laden runoff to allow fine sediments to settle-out before the runoff enters the water resource. The ends of the barrier should be up-turned to maintain the pool volume.

A shallow trench shall be excavated the width of the bale and to a minimum depth of 4 inches in which to bed the bale. The excavated soils are then used to seal the lower inside (up-slope) edge of the barrier. The bales should be set tightly together and entrenched with the baling string oriented on the sides (i.e., not touching the ground) in order to prevent deterioration of the string.

Every bale should be staked using 2 stakes per bale. The stakes should be driven in at angles such that it binds and forces abutting hay bales together.
Gaps between bales shall be packed with loose hay to prevent water from escaping between the bales.

Hay bales will not be placed in streams where flow is present or anticipated.

<u>Maintenance</u>
Once a week, or after rainstorms producing at least ½ inch of rainfall, whichever is more frequent, the contractor is responsible for inspecting all temporary erosion and sediment control barriers. Such inspection is necessary to ensure the structures are functioning properly as well as identifying new areas requiring installation. A maintenance log should be kept of all erosion control changes, improvements, and maintenance performed.

If any barriers are not functioning properly, they must be repaired or replaced. A sediment barrier is not functioning if:

- Water is flowing around the sides or under the barrier.
- Soil has built up behind the barrier to the point more than half-way up the hay bale or where there is excessive lean to the barrier.
- There is evidence of sedimentation such as gully erosion, slumping of banks, or the discoloration of water outside of the hay bale barrier.

Corrective measures include removing accumulated sediment from behind the barrier, re-staking, extending the barrier at the ends, or installing another barrier further up-slope.

It is not recommended that straw or hay bales be used for periods greater than 60 days.

<u>Removal</u>
Installed hay bales will be removed once it is evident that the soils have become stabilized and the potential for erosion no longer exists. In most cases, the hay bale barrier will not be removed until at least a healthy growth of vegetation is established on the disturbed site. Removal of hay bale barriers should be coordinated with CMP or their designated representative.

Any ridges, mounds of soil, or caught sediment remaining in place after the hay bales have been removed, must be leveled-off to conform to the existing grade. Any newly exposed soil that may erode must be seeded and mulched.

All removed hay bales must be properly disposed of, or broken up and used as mulch on the bare soils near the barrier.

6.3.1 Problems With Straw or Hay Bale Barriers

There are several situations where straw or hay bale barriers may be ineffective or cause problems:

1. When improperly placed and installed (such as staking the bales directly to the ground with no soil seal or entrenchment), hay bales allow undercutting and end flow.
2. When used in streams and drainage ways, high water velocities and volumes destroy or impair their effectiveness.
3. When bales are not inspected and maintained adequately.
4. When hay bale barriers are removed before up-slope areas have been permanently stabilized.
5. When hay bale barriers have not been removed after they have served their usefulness.

6.4 Erosion Control Mix Berms

<u>Composition</u>
Erosion control mix berms are made up of shredded bark, stump grindings, and composted bark. It may be made on a project site if adequate materials are available, however its composition needs to be a well-graded mix of different particle sizes. Wood chips, bark chips, ground construction debris and processed wood cannot make up the organic component of the mix. Be sure to consult with the project environmental inspector regarding the suitability of any erosion control mix material proposed for use.

<u>Installation</u>
Erosion control mix berms are simply placed on the surface of the ground and do not require any soil disturbance. The berm should be located in a similar manner to other sediment control barriers along contour, downslope of disturbed soils. Also similar to other sediment barriers, they should not be placed in areas of concentrated runoff, below culvert outlets, around catch basins, or at the bottom of a large contributing subwatershed. At the toe of shallow slopes less than 20 feet long, at a minimum berms should be 12” high and a minimum of 2 feet wide at their base. For longer or steeper slopes, the berms should be wider to accommodate additional runoff. They are ideal for installation on frozen ground, on shallow to bedrock soils, outcrops of bedrock, and heavily rooted forested areas (i.e., those areas where other barriers are difficult to install).

Erosion control mix can also be placed in a synthetic “sock” to create a contained stable sediment barrier. This is especially useful in areas where trenching is not feasible, such as frozen ground, across pavement, or compacted gravel. When in a sock, erosion control mix can staked in an area of concentrated flow (i.e., ditch or swale) as the netting prevents movement of the mulch mixture.

Maintenance
As with other barriers, inspection should be performed after each rainfall or daily during prolonged periods of rain. Accumulations of sediment should be removed when they reach half the height of the barrier, and the berms can be reshaped and new material can be added as needed.

Removal
In most cases, erosion control mix berms do not need to be removed. They will continue to function as they decompose, become part of the soil on the site and will naturally revegetate. If synthetic socks are used, the erosion control mix can be emptied from the sock and the socks can be disposed of offsite.

6.5 Temporary Sediment Traps

Temporary sediment traps function to slow or temporarily detain runoff and allow sediment to settle out of the water column prior to runoff leaving a project site. Sediment traps generally consist of natural or manmade depressions. Sediment traps are not designed for high volume or high velocity flows.

Installation
Areas draining to sediment traps should be relatively small. Sediment traps are routinely installed at the discharge end of a water bar or upgradient water diversion to treat runoff. Natural depressions can be used or modified, and small basins can be excavated. Structural erosion control devices can be installed along the downslope perimeter of natural or excavated sediment traps to increase filtration of any runoff that overtops the trap. Sediment traps should discharge to vegetated buffer areas.

Sediment traps may also be constructed using structural erosion controls such as hay bale corrals lined with geotextile fabric. Care should be taken to prevent existing vegetation or obstructions from tearing the fabric and allowing the runoff to escape the fabric untreated.

Maintenance
When sediment has accumulated to 50% of the capacity of the trap it should be removed and placed in an upland area and stabilized in a manner to prevent its entry into protected natural resources. Similarly, non-functioning or damaged geotextile fabric must be removed, disposed of properly and replaced as needed.

Removal
Temporary sediment traps shall be removed, and areas shall be regraded to original contours and stabilized with permanent non-structural controls until fully re-vegetated. All structural controls used to construct temporary sediment traps must be removed and disposed of properly.

6.6 Temporary Sediment Basins

Permanent sediment basins, designed by a qualified engineer, can be used during construction for temporary storage of stormwater and settling of sediments. Sediment basins should be constructed and stabilized prior to the remainder of the site being disturbed. Flow patterns across the site should be directed towards the sediment basin for treatment.

Installation of the sediment basin shall be completed per the design on the engineer-stamped drawings. Following its use as a temporary sediment basin, all collected sediment must be removed and necessary repairs made to allow for the intended permanent function of the engineered design. Sediments removed from the basin must be placed in an upland area and stabilized in a manner to prevent its introduction into protected natural resources.

7.0 NONSTRUCTURAL EROSION CONTROL MEASURES

7.1 Nonstructural Measures Defined

Nonstructural measures are temporary or permanent methods used to cover exposed soil areas to prevent erosion from occurring. Their purpose is to cover whole areas of exposed soil to prevent initial erosion of soil from a construction site.

Examples of nonstructural measures include hay or straw mulch, erosion control mix, matting, or seeding.

7.2 Importance of Nonstructural Measures

Nonstructural measures are important because they provide both temporary and permanent protective cover to exposed soils. Generally, they provide the first line of protection against erosion, and can be the most effective means of preventing erosion. This protection is important because exposed soils are easily eroded by wind or water. Some soils such as silts can easily be removed from a construction site by rainwater. The impact of individual raindrops on exposed soils can loosen soil particles, and these particles can then be carried off the work site by runoff and deposited into water resources including streams, rivers, wetlands, ponds, and lakes. Silt particles don’t settle out of water easily, and water siltation can pollute surface waters and harm aquatic creatures such as insects and fish. For example, brook trout, one of Maine’s premier game fish species, requires clear, high quality water in order to survive. Silty water can reduce spawning habitat, irritate fish gills, lower oxygen content in water, and make fish susceptible to diseases.

Dry soil conditions and high winds can also cause siltation. When small particle soils such as silts become dry, they have a baby powder-like texture and can easily be swept away by winds. Nonstructural measures help prevent wind erosion because they hold moisture next to the soil, keep the soil from drying out due to wind exposure, and prevent winds from carrying away dry soil particles. Keep in mind, however, that proper construction sequencing is invaluable (See Section 2.3).

7.3 Placement of Nonstructural Measures

Nonstructural measures should be used whenever there is a possibility that exposed soils on a construction site could wash into adjacent sensitive water resources. Temporary nonstructural measures such as hay or straw mulch should be spread on exposed soils within 100-feet of water resources within 48 hours of initial soil disturbance, or before any predicted storm event. There are two types of nonstructural measures: temporary and permanent. Temporary measures are typically used <u>during</u> construction, while permanent measures are usually applied <u>after</u> construction is complete (i.e., restoration). Provided below are general discussions and explanations of the common nonstructural measures that are used on CMP construction sites.

7.3.1 Temporary Measures

- Hay or straw mulch (unanchored on slopes less than 8%, anchored on slopes greater than 8%) on exposed soil areas and soil stockpiles in the construction area.
- Temporary seeding covered by hay or straw mulch on soil stockpiles or areas of exposed soil next to sensitive resources that are not scheduled for final restoration for 30 days (this only applies between the dates of April 16 to October 31 of any given year). Temporary seeding is not required during the Winter Construction Season.
- Erosion control mix can be used as a stand-alone temporary mulch on slopes that are 2 horizontal to 1 vertical, or less, on frozen ground, in forested areas, or at the edge of gravel parking and areas under construction. It should be applied at a thickness of 4 to 6 inches.
- Rolled Erosion Control Products (RECP's) such as Curlex or Jute matting, can be used on areas of high wind exposure, steep slopes (steeper than 8% grade), unstable soils, and stream/river bank restoration areas. Matting is typically anchored (usually with large staples, as recommended by the manufacturer). Although this type of material is usually used during final restoration, it is considered a temporary measure because it generally deteriorates within two years.

Table 5
Temporary Seeding Rates and Dates

Seed	Lb./Ac	Seeding Depth	Recommended Seeding Dates	Remarks
Winter Rye	112(2.0 bu)	1-1.5 in.	8/15-10/1	Good for fall seeding. Select a hardy species, such as Aroostook Rye.
Oats	80 (2.5 bu)	1-1.5 in.	4/1-7/1 8/15-9/15	Best for spring seeding. Early fall seeding will die when winter weather moves in, but mulch will provide protection.
Annual Ryegrass	40	.25 in.	4/1-7/1	Grows quickly but is of short duration. Use where appearance is important. With mulch, seeding may be done throughout growing season.
Sudangrass Perennial	40 (1.0 bu) 40 (2.0 bu)	.5-1 in. .25 in.	5/15-8/15 8/15-9/15	Good growth during hot summer periods. Good cover, longer lasting than Annual Ryegrass. Mulching will allow seeding throughout growing season.

Temporary mulch with or without dormant seeding			10/1-4/1	Refer to TEMPORARY MULCHING BMP and/or PERMANENT VEGETATION BMP.

Proper application rates, location, and seasonal consideration are provided in Table 6 on page 23 of this manual.

7.3.2 Permanent Measures

Uplands

- Permanent grass and legume seeding covered by hay or straw mulch on all areas that have been restored to final grade (this seeding generally applies between the dates of April 16 to October 31 of any given year). This is required to establish permanent, perennial, vegetative cover on exposed soils. Permanent seeding is not required during the Winter Construction Season, although dormant seeding may be performed. (See Section 8.0 for details on winter construction.)
- Seeds covered by anchored (usually with large staples) Curlex or jute matting in areas of high wind exposure, on steep slopes (steeper than 8% grade), unstable soils, and stream/river bank restoration areas.
- The soil may need to be properly prepared before any seeds are placed on the ground. This preparation may include addition of fertilizer (only in designated upland areas not adjacent to, or near waterbodies or wetlands, if in doubt ask the environmental or construction inspector) in areas that have been tested, and are found to be deficient in plant nutrients.
- Erosion control mix can also be used as a permanent mulch to provide a buffer around disturbed areas. It can be left in place to decompose and naturalize. It will eventually support vegetation, which should be promoted. If vegetation is desired in the short-term, legumes and woody vegetation can be planted, which will create additional stability.

Wetlands

- Wetland areas are to be seeded only with resource agency approved wetland seed mixes. If it is decided that wetlands will not be seeded, disturbed wetland will be graded to original contours, mulched with straw, and allowed to revegetate naturally.

As with the Temporary Measures, refer to Table 6 on page 23 for proper application rates, locations, and seasonal considerations.

For permanent seeding mixtures, consult the approved plans/proposal for the project, the environmental inspector, or Appendix A of the Maine Erosion and Sediment Control BMPs.

8.0 WINTER CONSTRUCTION CONSIDERATIONS

If a project is actively being constructed between November 1 and April 15 of any given year, sediment and erosion control guidelines developed by the Maine Department of Environmental Protection for projects occurring during the winter months must be followed.

Proper construction sequencing (Section 2.3) can greatly minimize environmental impact during winter construction. When in doubt, contact the project construction manager or environmental inspector with any questions.

Table 6 on page 23 highlights some of the major differences between the winter construction guidelines and normal BMPs used during construction and for temporary stabilization. The table presents differences for temporary measures that should be used during construction, and permanent measures when construction is completely done.

Table 6
Nonstructural Erosion Control Measures (Seasonal Differences in Construction BMP Requirements)

Dates	General Construction April 16 through October 31 of every year	Winter Construction November 1 through April 15 of every year
Mulch on slopes less than 8%	Within 100-feet of sensitive water resources apply hay and/or straw mulch at a minimum of 70 lbs./1000 square feet of exposed soil (about 2 bales). Must be done within 7 days of initial soil disturbance and before storm forecasted events, unless specified otherwise.	Within 100-feet of sensitive water resources apply and maintain properly anchored hay and/or straw mulch at a minimum of 150 lbs./1000 square feet of exposed soil (about 5 bales) at all times. (double the April 16 – October 31 rate)
Mulch on slopes greater than 8%	Hay or straw mulch can be applied without being anchored, though specific site conditions may require use of anchoring.	Apply mulch as specified above. Properly anchor with Curlex, jute matting, or similar mulch netting on upland slopes exceeding 8% and within 100 feet of streams if no construction activities are anticipated for 7 or more days.
Area of exposed soils allowed at any one time	No restriction on area exposed, but contractor must attempt to minimize amount of exposed soil at any one time, especially next to water resources.	Not more than one (1) acre of exposed (not mulched or otherwise devoid of vegetative cover) soil.
Sediment barriers	A single line of sediment barriers including silt fence, hay bales, or wood waste filter berms must be installed between water resources and disturbed soils.	If soil is frozen, wood waste filter berms **or** 2 lines of sediment barriers (including hay bales and silt fence) must be placed between water resources and disturbed soils.
Temporary seeding in uplands	If required, apply at the rate specified by the supplier, CMP Environmental Department, or Environmental Inspector. Cover with mulch.	Not required, but if temporary seeding is desired, it must be applied at a rate 3 times higher than the General Construction Season, and covered with mulch.
Temporary seeding in wetlands	Wetlands are not to be seeded unless done so with an agency-approved seed mix. Annual Rye Grass is not acceptable and shall not be used. Disturbed wetland areas will be mulched exclusively with straw.	Wetlands are not to be seeded unless done so with an agency approved seed mix. Annual Rye Grass is not acceptable and shall not be used. Disturbed wetland areas will be mulched exclusively with straw.
Permanent seeding in uplands	Site must be seeded at rate specified by the supplier and covered with hay or straw mulch. If needed, the site can be limed and fertilized.	Not required before April 16, but if dormant seeding is desired, the site should receive an adequate cover of loam, if necessary, be seeded at a rate 3 times higher than the General Construction Season, and covered with mulch at a minimum of 150 lbs./1000 square feet.
Permanent seeding in wetlands	Do not apply permanent seed mixes to wetland areas unless they are specially designated wetland seed mixes approved by a resource agency.	Do not apply permanent seed mixes to wetland areas unless they are specially designated wetland seed mixes approved by a resource agency.
Temporary seedbed preparation	Apply limestone and fertilizer (uplands only) according to soil test data. If soil test is not possible, 10-10-10 fertilizer may be applied at a rate of 600 lbs./acre and limestone at 3 tons/acre.	Not required, but seedbed can be prepared according to General Construction requirements.

Dates	General Construction April 16 through October 31 of every year	Winter Construction November 1 through April 15 of every year
Permanent seedbed preparation	Apply limestone and fertilizer (uplands only) according to soil test data. If soil test is not possible, 10-20-20 fertilizer may be applied at a rate of 800 lbs./acre and limestone at 3 tons/acre.	Not required before April 16, but if dormant seeding is desired, the seedbed can be prepared according to the General Construction requirements.
Temporary slope stabilization	Same as winter construction season, but mulch does not need to be anchored.	Anchored hay or straw mulch on slopes greater than 8% and drainage ways with greater than 3% slope as necessary. Wood waste mix can be used on slopes in place of anchored hay or straw mulch.
Maintenance of erosion controls	Same as winter construction guidelines.	All erosion controls should be inspected periodically to ensure proper function. If any evidence of erosion or sedimentation is evident, repairs should be made to existing controls or other methods should be used.
Inspection and monitoring	Monitoring should be performed as needed until a new, healthy vegetative cover is attained on the site. This applies to both temporary and permanent seeding.	Monitoring should be performed as needed to ensure proper stabilization and re-vegetation (both temporary and permanent). Starting in the spring following completion of the project, inspections should be performed until new, healthy vegetative cover is attained.

9.0 SITE RESTORATION STANDARDS

Following completion of the construction work, the contractor will be responsible for conducting site restoration work. The following guidelines will apply to all activities, including temporary and permanent roads, stream/wetland crossings, staging and work areas, and substation sites.

9.1 Procedure

At the completion of project construction in an area or at the end of the construction, CMP or their designated representative, the contractor, and any Third Party Inspector will review the project's restoration needs and prioritize the areas. This prioritization should consider time of year, ground conditions, re-vegetation probabilities, and equipment availability. A restoration "walk-through" is strongly recommended.

In many cases a site can and should be restored within hours of when the soil disturbance occurred. Often getting the equipment to a site that needs to be restored only creates more disturbed area to restore. It is important to "restore as you go" to reduce the equipment travel on temporary access roads. It can be particularly difficult to restore an area that was disturbed during winter construction activities in the spring or summer.

Likely areas of restoration include, but are not limited to:

- Around substation construction areas.
- Around pole and anchor pole placement.
- All wetland, stream, or brook crossings, particularly the approaches and any stream banks.
- Drainage ways or ditches.
- All temporary or permanent constructed roads, yarding, and staging areas.
- Cut banks.
- Steep slopes (over 8%).

9.2 Methods for Restoration

There are several methods of restoration for different areas.

1. All soil that is excavated, mounded, or deposited during construction will be re-graded or removed from the site as directed by CMP. All re-grading and redistribution of soil will be done to match existing grade.
2. The banks and bottoms of brooks, streams, and rivers will be restored to natural conditions. In general, any material or structure used at temporary crossings will be removed, and the bank and bottoms restored to their original depth and contour.
3. On permanent access roads, stream culverts and bridges will be left intact and in good repair to remain available for maintenance operations and/or public access (woods roads, camp roads, etc.).
4. On those construction roads to be closed to future vehicle traffic (as determined by CMP), bridges, culverts, and other temporary crossing or water diversion structures will be removed and the banks and bottoms restored to original conditions.

5. Previously installed water bars may remain or new ones will be installed at locations designated by CMP or their designated representative. To prevent accelerated soil erosion, such water bars will be installed on all access and construction roads to be closed to vehicle traffic and on steep sections of permanent roads. Permanent water bars will be constructed to a sufficient height and width to divert the amount of water anticipated at each location as well as to provide some post-project permanence to the site. Water bars on long-term temporary access roads will be constructed in such a manner that they will remain effective and require minimal maintenance, and will be permanently seeded to ensure their long-term stability.
6. All areas severely rutted by construction equipment will be re-graded and permanently revegetated.
7. Upon completion of the project, all disturbed areas will be permanently revegetated or otherwise permanently stabilized. This includes the restoration of all areas disturbed by pole installation, temporary access roadways, permanent access roadways, substation construction, and resource crossings. Restoration is generally assumed to be a well-established vegetative cover. All cut and fill slopes must be revegetated, stabilized with riprap, or stabilized with erosion control mix, as appropriate to the slope conditions.
8. Liming, fertilizing, and seeding requirements for permanent re-vegetation will depend upon the soil type and drainage condition of the site. In the absence of soil tests, permanent seeding will generally be done in accordance with "Procedures for Permanent Seeding for Erosion Control" found in Table 6 on page 23.
9. The contractor will be responsible for the proper maintenance of all revegetated areas until the project has been completed and accepted. Where seed areas have become eroded or damaged by construction operations, the affected areas will be promptly re-graded, limed, fertilized, and re-seeded as originally required.
10. The contractor will perform all erosion control work to the complete satisfaction of Central Maine Power Company before the work is accepted. Central Maine Power Company will base acceptance of the erosion control and stabilization work on a final inspection.

APPENDIX A

DEFINITION OF TERMS

APPENDIX A
DEFINITION OF TERMS

Adjacent to a natural resource: Within 75 feet of, or in a position to wash into, a water resource (river, stream, brook, pond, wetland, or tidal area).

Annual seed mix: Seed mixture largely made up of plants that only persist one growing season.

Brook: Essentially the same as a stream, a water course that has a defined channel, a gravel, sand, rock or clay base, and flows at least part of the year. It may be a dry channel part of the year.

Corduroy: Logs greater than 3 inches in diameter at the small end and at least 18 feet long that are placed perpendicular to travel direction, on approaches to and in wetlands for crossings. The purpose of the logs is to prevent rutting and preserve vegetation root integrity in and adjacent to wetland areas. May also be used on approaches to mats or bridge stream crossings.

Crossing: Any activity extending from one side to the opposite side of a sensitive natural resource whether under, through, or over that resource. Such activities include, but are not limited to, roads, fords, bridges, culverts, utility lines, water lines, sewer lines, and cables, as well as maintenance work on these crossings. Crossings should be done to minimize impact. For example, crossing at a right angle to the resource and finding the driest or narrowest spot is one method for minimizing impact.

Cross-sectional area: The cross-sectional area of a stream channel is determined by multiplying the stream channel width by the average stream channel depth. The stream channel width is the straight-line distance from the normal high water line on one side of the channel to the normal high water line on the opposite side of the channel. The average stream channel depth is the average of the vertical distances from a straight line between the normal high water marks of the stream channel to the bottom of the channel.

Culvert: A pipe or box structure of wood, metal, plastic, or concrete used to convey water.

Erosion: Movement of earthen material by water or wind.

Erosion control blanket (matting): Manufactured material made out of natural or synthetic fiber designed to control movement of earthen material when installed properly.

Erosion control mix: Erosion control mix consists primarily of organic materials such as shredded bark, wood chips, stump grindings, composted bark, or similar materials. Ground construction debris or reprocessed wood products are not acceptable for use in erosion control mix. It contains a well-graded mix of particle sizes and may contain rocks up to 4 inches in diameter. Properly manufactured mix will have organic matter content between 80 and 100 percent (dry weight), 100 percent of particles must pass a 6-inch screen, the organic portion needs to be fibrous and elongated, it may contain only small proportions of silts, clays, or fine sand, and its pH should be between 5.0 and 8.0. Its applications include erosion control berms and mulch.

Erosion control plans: Written guidelines specific to a project or activity, describing various techniques and methods to control erosion for specific construction activities.

Fill: Any earth, rock, gravel, sand, silt, clay, peat, or debris that is put into or upon, supplied to, or allowed to enter a water body or wetland. Material, other than structures, placed in or adjacent to a water body or wetland.

Filter strip: Undisturbed areas of ground consisting of natural vegetation and natural litter such as leaves, brush, and branches, located between a water resource and access road, skid road or trail, or other area of disturbed soil.
Ford: A permanent crossing of a stream utilizing an area of existing, non-erodible substrate of the stream, such as ledge or cobble, or by placing non-erodible material such as stone or geotextile on the stream bottom.
Geotextile, Non-woven: Synthetic material made of spun polypropylene fiber used to support wetland fill or stabilize soils.
Geotextile, Woven: Synthetic material of woven polypropylene used to stabilize soils and make sediment barriers (silt fence).
Great pond: An inland water body which in a natural state has a surface area in excess of 10 acres, and any inland water body which is artificially formed or increased which has a surface area in excess of 30 acres.
Intermittent watercourse: Water course that has water in it only part of the year. It is still considered a natural resource.
Mats: Pre-constructed, portable, timber platforms used to support equipment or travel in or over wetlands or water bodies.
Mulch: Temporary erosion control such as hay, bark, or some similar natural material utilized to stabilize disturbed soil.
Perennial seed mix: Seed mixture made up of seeds from plants that persist for several years.
Perennial watercourse: A river, stream, or brook depicted as a solid blue line on the most recent edition of a United States Geological Survey 7.5 minute series topographic map. Typically has water in it year round.
Permanent access road: Project access road that is not restored after project construction completion. Permanent access roads should be designed and constructed so they are not an erosion problem.
Permanent stabilization: Establishment of a permanent vegetative cover on exposed soils where perennial vegetation is needed for long-term protection.
Permanent vegetative cover: Perennial seed stock, including but not limited to grasses and legumes that persist for more than several growing seasons.
Protected Natural Resource: Coastal sand dune system, coastal wetlands, significant wildlife habitat, fragile mountain areas, freshwater wetlands, community public water system primary protection areas, great ponds or rivers, streams, or brooks. (From the Maine Natural Resources Protection Act, 38 M.R.S.A. Section 480-B., revised 2007).
Riprap: Heavy, irregular-shaped rocks that are fit into place, usually without mortar, on a slope in order to stabilize and prevent soil erosion.
Sediment barrier: Staked hay bales, silt fence, or similar materials placed in a manner to intercept silt and sediment laden water runoff.
Sedimentation: Deposition of earthen material in a water body or wetland.
Sensitive Natural Resource: Area that deserves special attention because it is significant wildlife habitat, fisheries habitat, or has other natural resource values. These areas may require the use of minimum impact construction techniques such as use of mats, leaving vegetation intact for buffers, special timing of construction, or other specific techniques.
Settling basin (sediment/catch basin): Excavated pit placed to intercept water running off disturbed soils or dirt road bed. Usually used only where filter strip is inadequate to protect a stream, pond, or wetland from silt and sediment.

Silt fence: Woven geotextile sediment barrier. Proper installation requires placement on-contour and keying the fabric in at ground level.
Steep slopes: Slopes in excess of eight (8) percent.
Stone check dam: A small, temporary dam constructed across a swale or drainage ditch. The purpose is to reduce the velocity of concentrated flows, reducing erosion and trapping sediment generated in the ditch.
Stream: Generally, a channel between defined banks with a gravel, sand, rock, or clay base that flows at least part of the year. It may be a dry channel part of the year. The Maine Natural Resources Protection Act contains a more detailed definition.
Structure: Anything built for the support, shelter, or enclosure of persons, animals, goods, or property of any kind, together with anything constructed or erected with a fixed location on or in the ground. Examples of structures include buildings, utility lines, and roads.
Temporary access road: A road constructed solely for project access which is restored to original grade upon project completion, if not sooner. All areas disturbed by access road construction and use will be stabilized, including road ditches, travel ways, and slopes back to vegetated conditions. In most cases, any roadway ditches associated with temporary access roads should be refilled to reestablish pre-development drainage conditions.
Temporary stabilization: Mulch, matting, or seed, or a combination thereof, utilized to stabilize soil. Soil stockpiles left in place longer than 14 days must have temporary stabilization.
Temporary vegetative cover: An annual seed mixture, typically annual rye and oats.
Topography: The contour and elevation of the surface of the ground.
Turn out: Water diversion that directs water out of a ditch or off a travel-way and into a vegetated buffer.
Upland edge: The area of uplands alongside a wetland, stream, or water body.
Wastes requiring special handling: Wastes generated from construction activity including engine oil, hydraulic oil, gear oil, diesel, gasoline, or coolants.
Water bar: Constructed bar across an access road or skid trail that directs surface water off the road or trail into a stable vegetated surface or filter strip. They are used as a temporary measure on active roads or when closing roads permanently to prevent erosion.
Water body: River, stream, brook, pond, wetland, or tidal area.
Water resource: River, stream, brook, pond, wetland, or tidal area.
Wetland: An area that is inundated or saturated by surface or groundwater at a frequency and for a duration sufficient to support, and which under normal circumstance do support, a prevalence of wetland vegetation typically adapted for life in saturated soils. The Maine Natural Resources Protection Act contains a more detailed definition.

APPENDIX B

CONSTRUCTION MATERIALS SOURCE LIST

APPENDIX B

CONSTRUCTION MATERIALS SOURCE LIST

The following list of vendors has been selected given the wide variety of construction materials they offer. The list is not meant to be all-inclusive or an indication of favored vendors.

W.H. Shurtleff Company (Culverts, Geotextiles)

One Runway Road
Suite 8
South Portland, Maine 04106-6169
1-800-633-6149
www.whshurtleff.com

A. H. Harris (Geotextiles, i.e. Curlex Excelsior Blankets)

22 Leighton Road
Augusta, Maine 04332
(207) 622-0821
www.ahharris.com

585 Riverside Street
Portland, Maine 04103
(207) 775-5764

North American Green (Erosion control materials)

Maine Distributor:
E.J. Prescott
P.O. Box 600
32 Prescott Street, Libby Hill Business Park
Gardiner, Maine 04345
(207) 582-1851
www.ejprescott.com

New England Organics (Erosion Control Mulch)

135 Presumpscot Street, Unit 1
Portland, ME 04103
1-800-933-6474
www.newenglandorganics.com

APPENDIX C
OTHER RECOMMENDED REFERENCE MANUALS

APPENDIX C
OTHER RECOMMENDED REFERENCE MANUALS

Maine Erosion and Sediment Control Best Management Practices (BMPs). Manual for Designers and Engineers. Bureau of Land Resources, Maine Department of Environmental Protection, Augusta, Maine. October 2016. http://www.maine.gov/dep/land/erosion/escbmps/esc_bmp_engineers.pdf

Maine Erosion and Sediment Control Practices Field Guide for Contractors. Bureau of Land Resources, Maine Department of Environmental Protection, Augusta, Maine. 2014. http://www.maine.gov/dep/land/erosion/escbmps/esc_bmp_field.pdf

Best Management Practices for Forestry: Protecting Maine's Water Quality. Maine Forest Service, Augusta, Maine. 2004. www.maine.gov/doc/mfs/pubs/bmp_manual.htm

Forest Transportation Systems: Roads and Structures Manual. Seven Islands Land Company, Bangor, Maine. Third Edition, 1999.

APPENDIX D

CONSTRUCTION TECHNIQUE ILLUSTRATIONS

CULVERT CROSSING

IMPROPER INSTALLATION

- **Culvert is undersized, allowing overflow to cross travel-way**
- **Insufficient cover thickness over culvert**
- **Outlet is not stable, leading to erosion**
- **Culvert outlet is set too high causing it to be impassable to fish and other aquatic organisms**

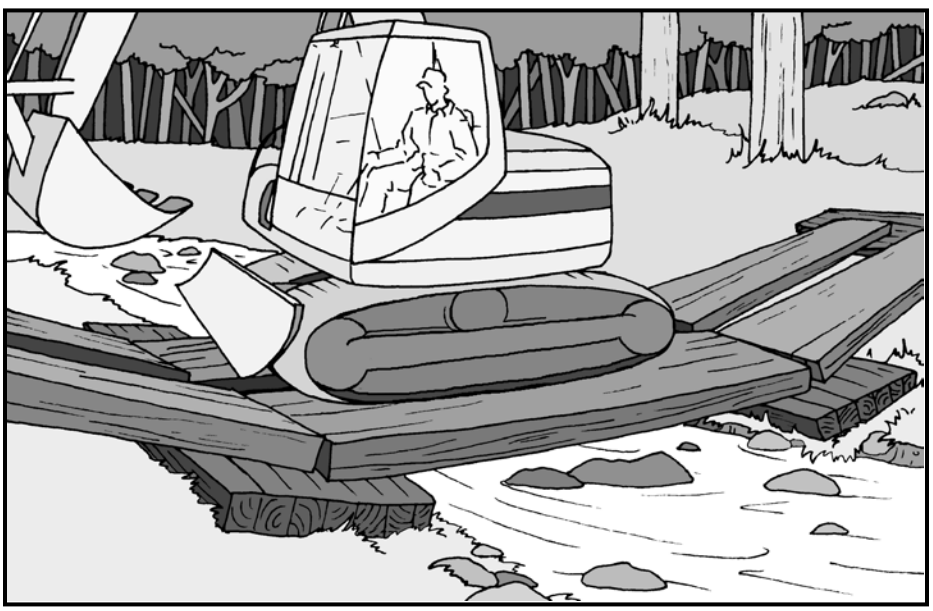
PROPER INSTALLATION

- **Culvert is adequately sized for flow**
- **Sufficient cover thickness over culvert**
- **Inlet and outlet are adequately supported by gravel and rock to protect and maintain stability**
- **Outlet is properly seated at or below stream bottom allowing aquatic organisms to access upstream**

CRANE MATS – WATERBODY CROSSING

IMPROPER INSTALLATION

- **Mats not long enough to keep equipment out of water and wetland soils**
- **Lacks cross supports which elevate travel mat**
- **Mats do not extend far enough to protect wetland soils from rutting**



PROPER INSTALLATION

- **Mats are elevated by cross-supports on stream banks, keeping them up out of water and out of wet soils**
- **Water flows under mats**
- **Mats extend over approaches to crossing protecting soils from rutting and eroding**
- **Equipment stays out of water and wetlands**

CRANE MATS – WETLAND CROSSING

IMPROPER INSTALLATION

- **Long axis of mats is not perpendicular to travel direction**
- **Mats are working down into wetland causing significant disturbance and picking up mud**
- **Mats do not extend beyond wetland edge to solid ground**

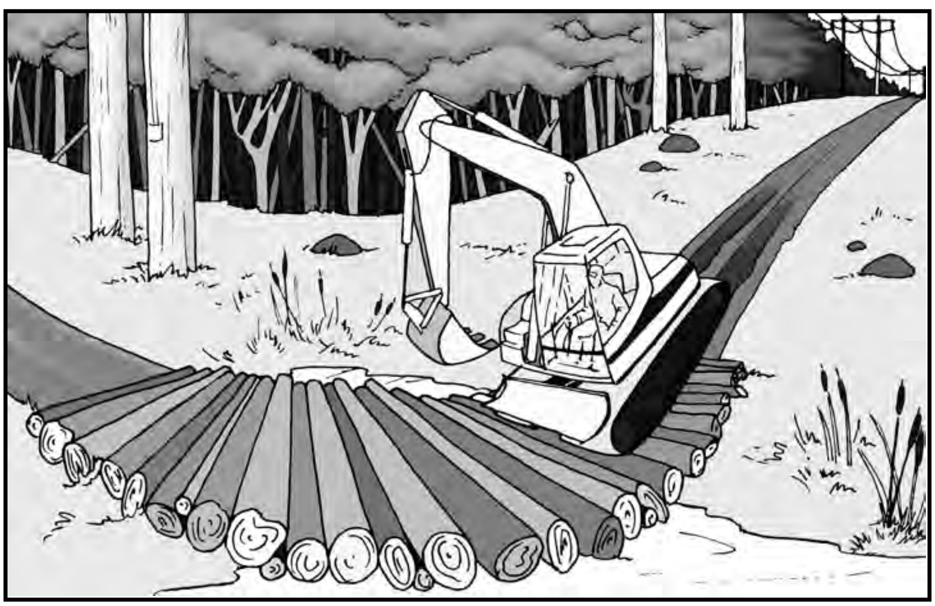
PROPER INSTALLATION

- **Correct orientation relative to travel direction**
- **Entire wetland is spanned, preventing rutting at ends of crossing**

CORDUROY CROSSING

IMPROPER INSTALLATION

- **Insufficient corduroy to support equipment**
- **Corduroy is sunken into wetland soil**
- **Approaches are steep, rutted, and are not protected with additional corduroy or slash**
- **Flow is interrupted, and water is soiled with mud and silt**



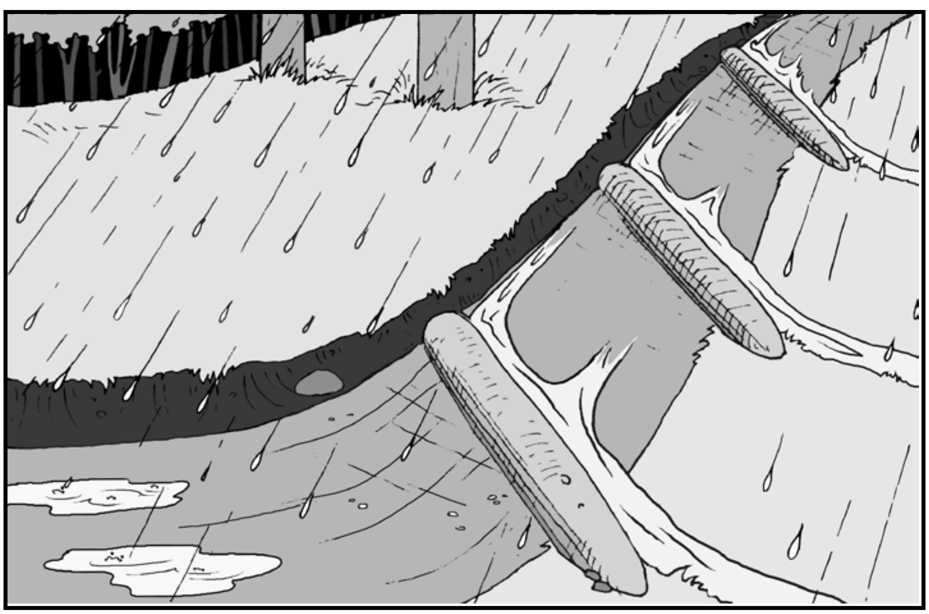
PROPER INSTALLATION

- **Adequate amount of layered corduroy to protect soil from rutting**
- **Approaches are protected from rutting by extension of corduroy beyond edges of crossing**
- **Flow is maintained and water is clear of mud and silt**

WATER BARS

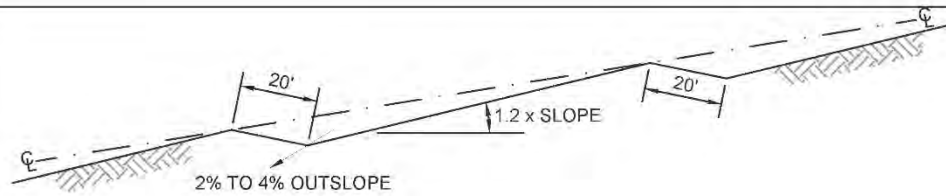
IMPROPER INSTALLATION

- Flow directed to uphill side on upper bar
- Angle of lower bar is too shallow
- Lower bar does not extend far enough, allowing water to escape around ends
- Bars are not high enough, allowing water to flow over top, eroding them

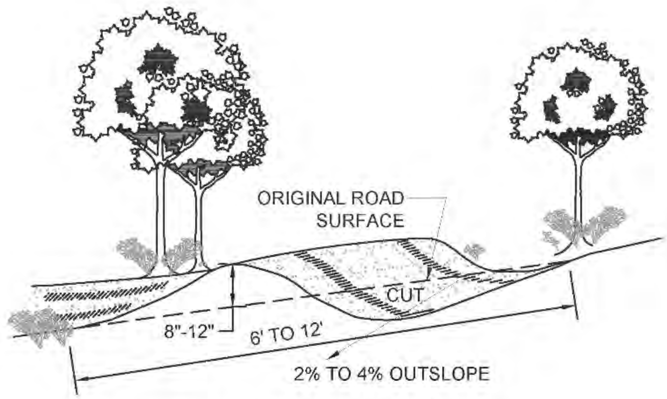


PROPER INSTALLATION

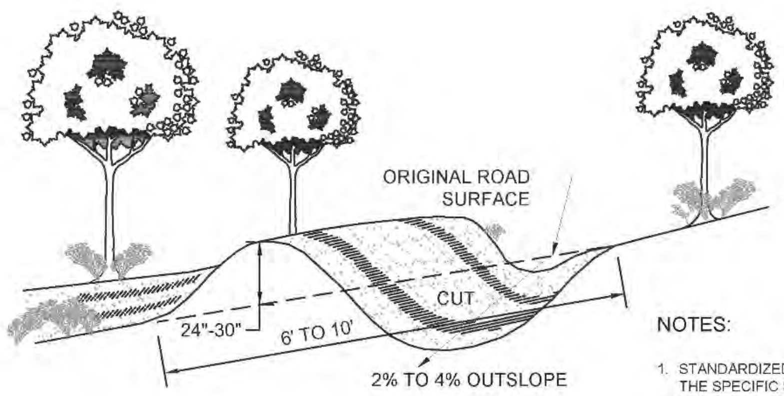
- Bars are at moderate angles
- There are enough bars to divert all water flowing down road
- Bars are high enough to prevent water from flowing over them
- Bars extend beyond edges of road, preventing water from flowing around them



BROAD BASE DIPS ON ROAD



SHALLOW WATER BAR



DEEP WATER BAR

NOTES:

1. STANDARDIZED DESIGNS MUST BE ADAPTED TO THE SPECIFIC SITE.
2. CONSTRUCT WATER BAR IN ACCORDANCE WITH MAINE EROSION AND SEDIMENT CONTROL PRACTICES FIELD GUIDE FOR CONTRACTORS, LATEST EDITION.

SCALE: N.T.S.

CENTRAL MAINE POWER

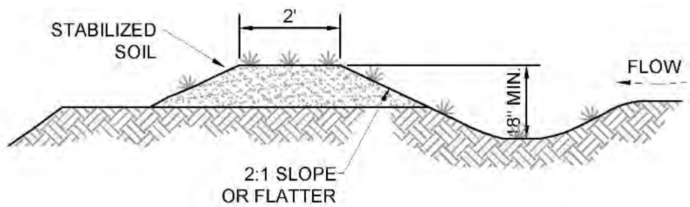
CENTRAL MAINE POWER COMPANY

TYPICAL WATER BAR DETAIL

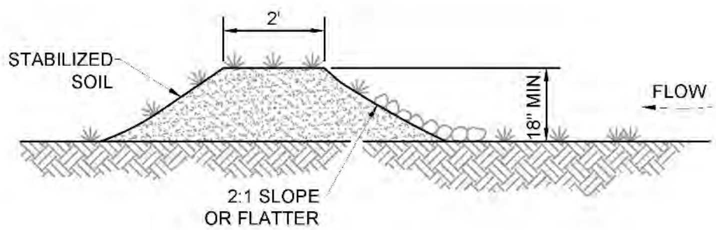
UPGRADIENT RUNOFF DIVERSION

NOTES:

1. ANGLE DIVERSION AWAY FROM SLOPE, WITH A 2-3% DOWNWARD GRADIENT.
2. DIVERSION SHALL DISCHARGE DIRECTLY TO EITHER A PLUNGE POOL, LEVEL SPREADER OR OTHER ENERGY DISSIPATER.
3. STABILIZE WITH MATERIAL THAT IS APPROPRIATE FOR THE SLOPE AND EXPECTED RUNOFF (EROSION CONTROL BLANKETS, GRAVEL OR RIPRAP).
4. CONSTRUCT DIVERSION IN ACCORDANCE WITH MAINE EROSION AND SEDIMENT CONTROL PRACTICES FIELD GUIDE FOR CONTRACTORS, LATEST EDITION.



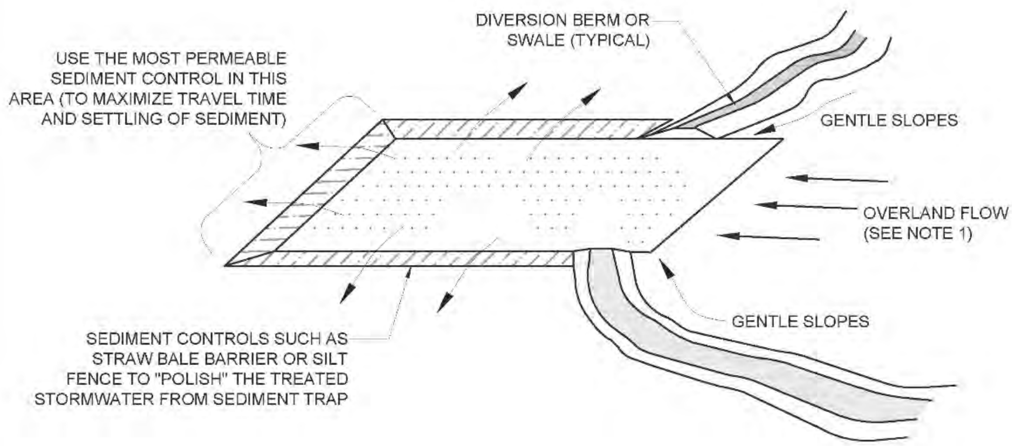
DIVERSION WITH EXCAVATION
SCALE: N.T.S.

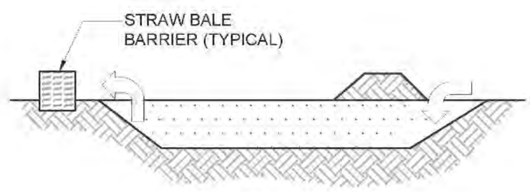


DIVERSION WITH FILL
SCALE: N.T.S.

CENTRAL MAINE POWER	CENTRAL MAINE POWER COMPANY
	TYPICAL UPGRADIENT RUNOFF DIVERSION DETAIL

TEMPORARY SEDIMENT TRAP





NOTES:

1. MAXIMUM AREA FOR OVERFLOW SEDIMENT TRAP IS USUALLY 1 ACRE. MUST HAVE GENTLE SLOPES (LESS THAN 2% GENERALLY) AND PREDOMINATELY OVERLAND SHEET FLOW.
2. MAXIMUM PERMANENT WET DEPTH IS 2 FEET. OVERFLOW SEDIMENT TRAPS MAY NOT BE EFFECTIVE FOR HIGH GROUNDWATER TABLE AND INFLOWS.
3. CONSTRUCT SEDIMENT TRAP IN ACCORDANCE WITH MAINE EROSION AND SEDIMENT CONTROL PRACTICES FIELD GUIDE FOR CONTRACTORS, LATEST EDITION.

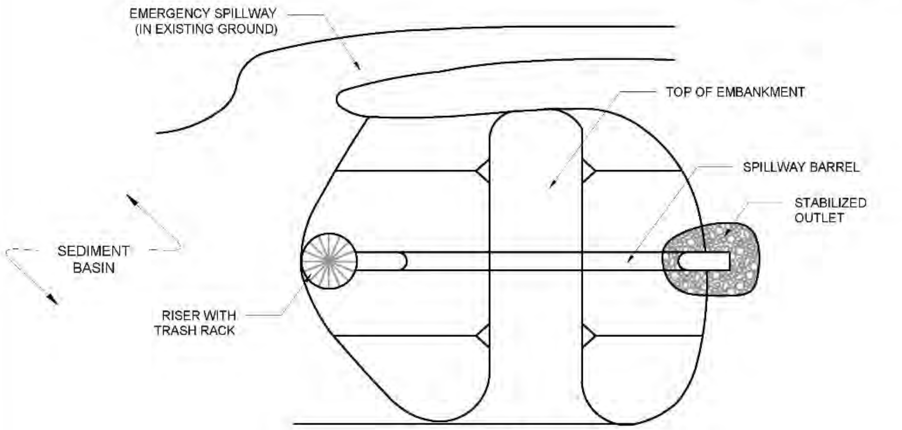
SCALE: N.T.S.

CENTRAL MAINE POWER	CENTRAL MAINE POWER COMPANY
	TYPICAL SEDIMENT TRAP DETAIL

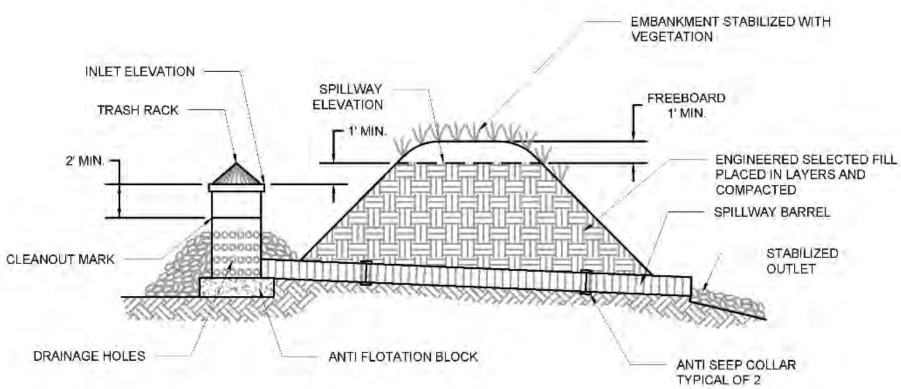
TEMPORARY SEDIMENT BASIN

NOTES:

1. THE BASIN'S LENGTH TO WIDTH RATIO SHALL BE 2:1 OR FLATTER.
2. BASIN SHALL BE LOCATED MORE THAN 100 FEET AWAY FROM ANY MAPPED OR DELINEATED NATURAL RESOURCE AND SHALL NOT DIRECTLY DISCHARGE TO A STREAM.
3. STABILIZE BASIN WITHIN 7 CALENDAR DAYS WITH RIPRAP, EROSION CONTROL MIX OR AN ANCHORED EROSION CONTROL BLANKET.
4. CONSTRUCT BASIN IN ACCORDANCE WITH MAINE EROSION AND SEDIMENT CONTROL PRACTICES FIELD GUIDE FOR CONTRACTORS, LATEST EDITION.



PLAN
SCALE: N.T.S.



SECTION
SCALE: N.T.S.

CENTRAL MAINE POWER

CENTRAL MAINE POWER COMPANY

TYPICAL SEDIMENT BASIN DETAIL

SEDIMENT BARRIER – HAY BALES

PROPER INSTALLATION

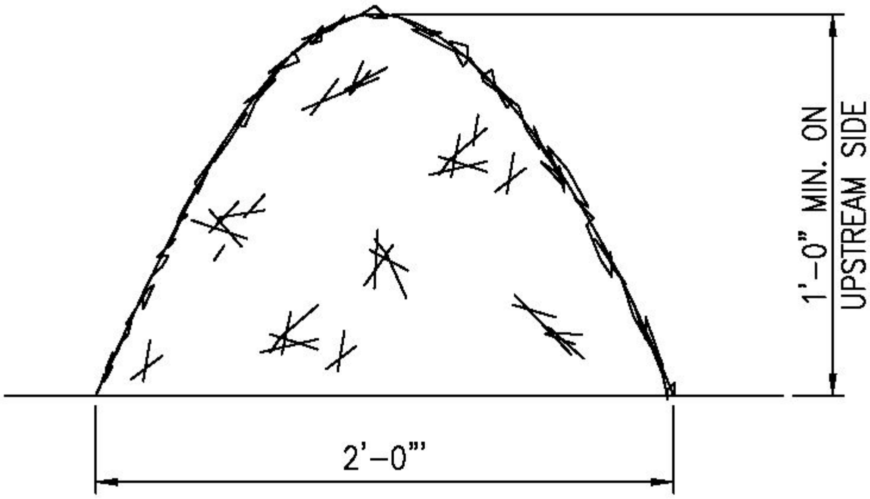
- **Dug trench to key bales into ground**
- **Stakes placed and driven in at angles to snug bales together**
- **Excess dirt used to cover openings and cracks**

SEDIMENT BARRIER – SILT FENCE

PROPER INSTALLATION

- **Dug trench to key material into ground**
- **Stakes are placed facing away from disturbed area**
- **Excess material on bottom is buried with excess dirt to prevent water from flowing under fence**

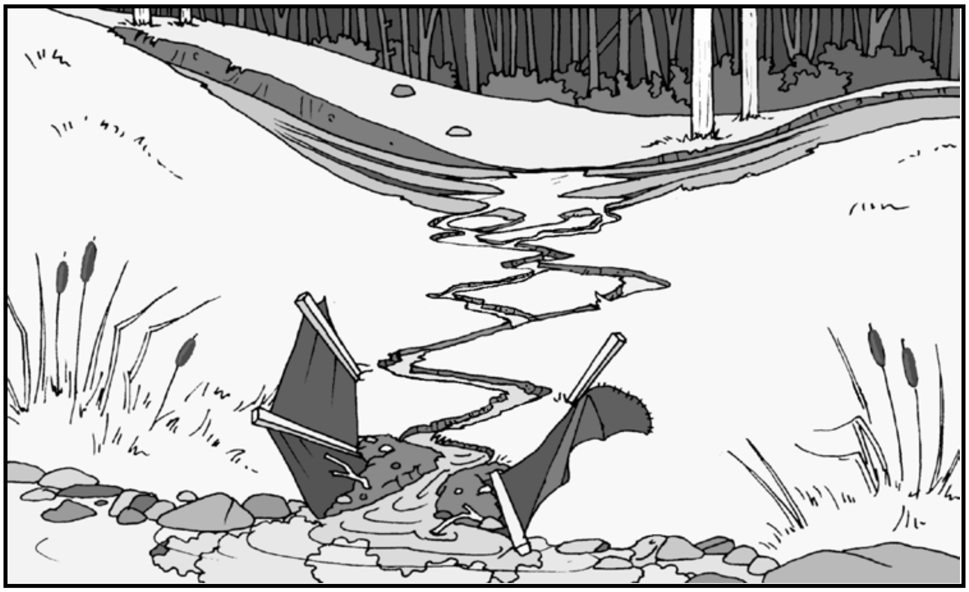
EROSION CONTROL MIX BERM DETAIL



- Use erosion control mix berm in place of silt fence and/or hay bale sediment barriers
- Erosion control soil/bark mix shall consist of: shredded bark, stump grindings, composted bark or flume grit and fragmented wood generated from water-flume log handling systems. The mix shall conform to the following:

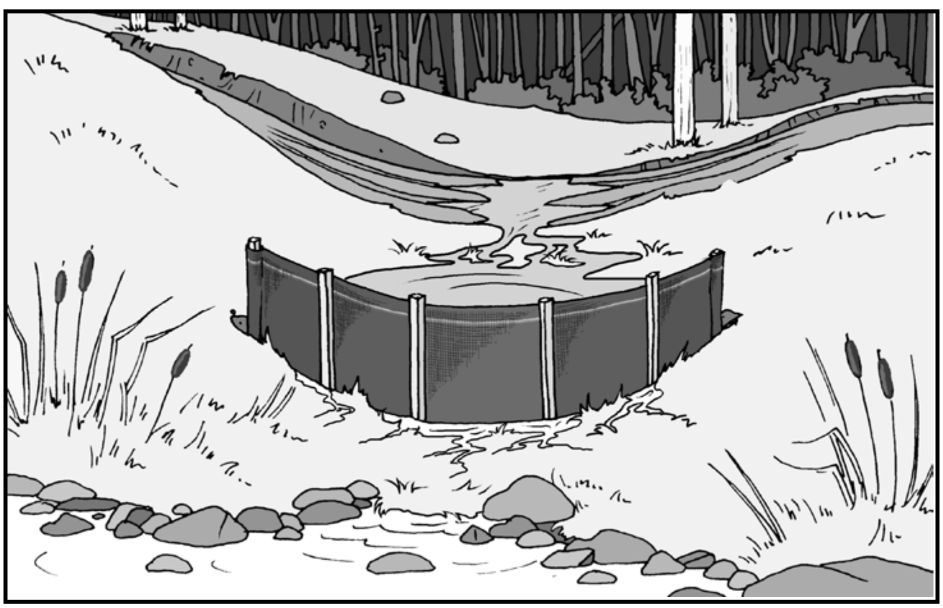
1. pH: 5.0 to 8.0
2. Screen Size: 6" – 100% passing
   ¾" – 70% to 85% passing
   Mix shall not contain large portions of silts, clays or fine sands
3. Organic material: 20% - 100% (dry weight basis)
   Organic portion must be fibrous and elongated
4. Soluble salts shall be <4.0 mmhos/cm

SEDIMENT BARRIER – SILT FENCE



IMPROPER INSTALLATION

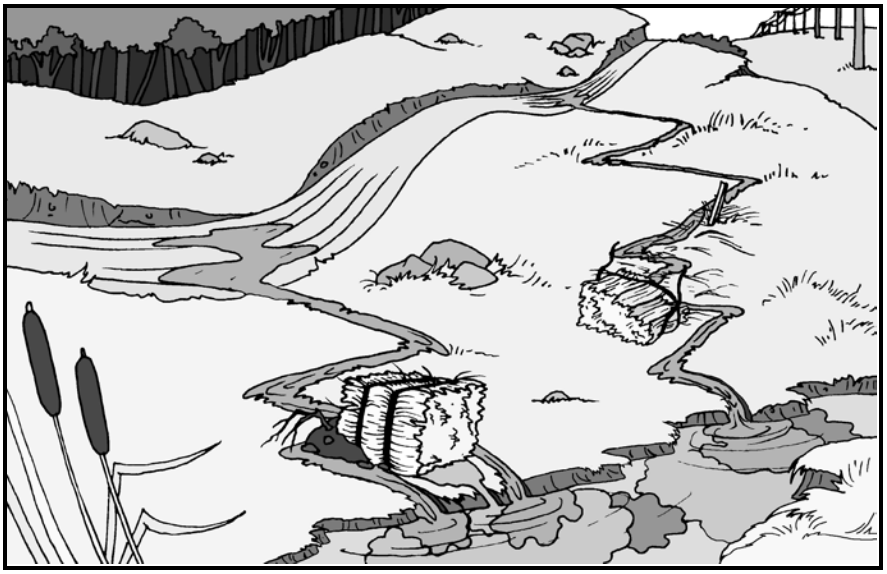
- **Fence located too far from road and too close to resource**
- **Stakes installed on wrong side of fence**
- **Needs maintenance (restaking, restapling, or even replacement)**
- **Placed in concentrated flow**



PROPER INSTALLATION

- **Adequate distance from road and resource allows road to capture and slow water, and allows silt fence to filter it before reaching resource**
- **Stakes placed on correct side; facing resource, while filter fabric faces disturbed area**
- **Adequate length; fence is long enough and turned uphill at ends to prevent water from escaping around edges**

SEDIMENT BARRIER – HAY BALES



IMPROPER INSTALLATION

- **Placed in concentrated flow**
- **Hay bales are not staked**
- **Not enough hay bales to adequately capture and slow flow**
- **Too far from source of runoff and sediment**
- **Improper orientation of bales; horizontal grass fibers do not provide adequate filtration, and strings on ground rot and bales to fall apart**

PROPER INSTALLATION

- **Staked properly; bales are secure and snug to one another**
- **Sufficient number of bales to slow flow and insure that no water escapes around edges**
- **Positioned close to disturbance, and far from resource to allow proper filtration**
- **Vertical orientation of grass fibers provides adequate filtration**
- **Placed along contour to capture sheet flow**

APPENDIX E

EROSION AND SEDIMENTATION CONTROL LAW* 38 M.R.S.A. § 420-C

APPENDIX E

EROSION AND SEDIMENTATION CONTROL LAW*

38 M.R.S.A. § 420-C

A person who conducts, or causes to be conducted, an activity that involves filling, displacing or exposing soil or other earthen materials shall take measures to prevent unreasonable erosion of soil or sediment beyond the project site or into a protected natural resource as defined in section 480-B. Erosion control measures must be in place before the activity begins. Measures must remain in place and functional until the site is permanently stabilized. Adequate and timely temporary and permanent stabilization measures must be taken and the site must be maintained to prevent unreasonable erosion and sedimentation.

This section applies to a project or any portion of a project located within and organized area of this State. This section does not apply to agriculture fields. Forest management activities, including associated road construction or maintenance, conducted in accordance with applicable standards of the Maine Land Use Regulation Commission, are deemed to comply with this section. This section may not be construed to limit a municipality's authority under home rule to adopt ordinances containing stricter standards than those contained in this section.

* The Erosion and Sedimentation Control Law is administered by the Maine Department of Environmental Protection (MDEP), Augusta, Maine. Please contact the MDEP with specific questions regarding this law.

APPENDIX F

MAINE SLASH LAW* 12 M.R.S.A. § 9333

APPENDIX F

MAINE SLASH LAW*

12 M.R.S.A § 9333

§9333. Disposal along railroad and utility lines

*1. **Stumpage owner**. A stumpage owner, operator, landowner or agent who cuts or causes or permits to be cut any forest growth on lands that are within or border the right-of-way of a railroad, a pipeline, or an electric power, telegraph, telephone or cable line may not place slash or allow it to remain on the ground within the right-of-way or within 25 feet of the nearer side of the right-of-way.*

*2. **Construction**. Slash accumulated by the construction and maintenance of a railroad, a highway, a pipeline or electric power, telegraph, telephone or cable line may not be left on the ground but must be hauled away, burned or chipped. Slash may not be left or place within the right-of-way or within 25 feet of the nearer side of the right-of-way. If a burning permit is denied or revoked under this chapter, the director may allow logs that are too large to be chipped to remain in the right-of-way until the director determines that their removal is economically feasible.*

*3. **Utility line maintenance**. Slash accumulated by the periodic maintenance of a pipeline or an electric power, telegraph, telephone or cable line may be disposed of in the following manner.*

- *A. Slash with a diameter of 3 inches or less may be left in piles on the ground within the maintained portion of the right-of-way. A pile may not be higher than 18 inches from the ground or longer than 50 feet and must be separated from other piles by a minimum of 25 feet in every direction. A buffer strip with a minimum width of 10% of the total width of the maintained right-of-way must be kept totally free of slash with a diameter of 3 inches or less.*
- *B. Slash with a diameter of more than 3 inches must be removed, chipped or limbed and placed on the ground surface. The pieces must be separated and may not be piled one piece over another. Slash of this size may be left within the maintained buffer strips.*
- *C. If a utility line right-of-way is adjacent to a road, slash that is 3 inches or less in diameter must be removed, burned or chipped. Slash with a diameter of more than 3 inches may be left on the ground within the right-of-way and must not be limbed and separated and may not be piled one piece over another. Usable timber products generated from the maintenance of a utility right-of-way may be piled within the right-of-way but must be removed within 30 days.*

* Note that this is an excerpt from the full text of the law. Please contact the Maine Forest Service, Augusta, Maine, for the full text of the law or with specific questions regarding the Slash Law.

APPENDIX G

CULVERT SIZES FOR STREAM CROSSINGS

(3X RULE)

CULVERT SIZES (ROUND) FOR STREAM CROSSINGS (3x RULE)

AVERAGE STREAM WIDTH

Take two measurements across the stream from bank to bank where you intend to place the culvert. Measurements should be taken at the normal high water line (NHWL). To find the NHWL during low flow periods look for water stains on rocks or a debris line along the bank. Add the first measurement to the second and divide this number by 2. This equals the average stream width. **Example: 36in. + 47 in. = 83in. 83÷2 = avg. stream width of 41.5 inches. (Round up to 42in.)**

AVERAGE STREAM DEPTH

Take 3 measurements from the bottom of the stream to the NHWL.
Add the measurements together and divide this number by 3. This equals the avg. stream depth.
Example: 12in. + 16in. + 14in. = 42in. 42÷3 = average stream depth of 14 inches.

USING THE TABLE

Take the average width and depth figures and determine where they intersect on the table above. *For example, for an average stream width of 42 inches (on the left side of the table), and an average stream depth of 14 inches (along the top of the table), the intersect shows a culvert diameter of 48 inches.

Average Stream Width		Average Stream Depth (Inches)														
Feet	Inches	2	4	6	8	10	12	14*	16	18	20	22	24	26	28	30
1	12	12	15	18	21	21	24	30	30	30	30	36	36	36	36	42
1.5	18	12	18	21	24	30	30	36	36	36	42	42	42	42	48	48
2	24	15	21	24	30	30	36	36	42	42	48	48	48	54	54	54
2.5	30	15	21	30	30	36	42	42	48	48	48	54	54	60	60	60
3	36	18	24	30	36	42	42	48	48	54	54	60	60	60	66	66
3.5	**42***	18	30	36	36	42	48	**48**	54	54	60	60	66	66	72	72
4	48	21	30	36	42	48	48	54	54	60	66	66	66	72	72	78
4.5	54	21	30	36	42	48	54	54	60	66	66	72	72	78	78	84
5	60	21	30	42	48	48	54	60	66	66	72	72	78	78	84	84
5.5	66	24	36	42	48	54	60	60	66	72	72	78	78	84	84	90
6	72	24	36	42	48	54	60	66	66	72	78	78	84	90	90	96
6.0	78	24	36	42	54	60	60	66	72	78	78	84	90	90	96	96
7	84	30	36	48	54	60	66	72	72	78	84	84	90	96	96	102
7.5	90	30	42	48	54	60	66	72	78	84	84	90	96	96	102	102
8	96	30	42	48	54	66	66	72	78	84	90	90	96	102	102	108
8.5	102	30	42	48	60	66	72	78	84	84	90	96	102	102	108	108
9	108	30	42	54	60	66	72	78	84	90	96	96	102	108	108	114
9.5	114	30	42	54	60	66	72	78	84	90	96	102	102	108	114	114
10	120	30	48	54	66	72	78	84	90	96	96	102	108	114	114	120
10.5	126	36	48	54	66	72	78	84	90	96	102	108	108	114	120	120
11	132	36	48	60	66	72	78	84	90	96	102	108	114	114	120	126
11.5	138	36	48	60	66	78	84	90	96	102	108	108	114	120	126	126
12	144	36	48	60	66	78	84	90	96	102	108	114	120	120	126	132
12.5	150	36	48	60	72	78	84	90	96	102	108	114	120	126	132	132
13	156	36	54	60	72	78	90	96	102	108	114	114	120	126	132	138
13.5	162	36	54	66	72	84	90	96	102	108	114	120	126	132	132	138
14	168	36	54	66	72	84	90	96	102	108	114	120	126	132	138	144
14.5	174	36	54	66	78	84	90	96	108	114	120	126	126	132	138	144
15	180	42	54	66	78	84	96	102	108	114	120	126	132	138	144	144

EXHIBIT 8 CMP ENVIRONMENTAL CONTROL REQUIREMENTS

ENVIRONMENTAL CONTROL REQUIREMENTS
FOR CENTRAL MAINE POWER COMPANY CONTRACTORS & SUBCONTRACTORS
OIL, HAZARDOUS MATERIALS, AND WASTE
February 2017

Following are requirements for the proper management of oil, hazardous materials, and waste, by contractors and subcontractors of Central Maine Power Company (CMP). All contractors and subcontractors are required to comply with these requirements while working for or on behalf of CMP.

Failure to abide by these requirements may constitute grounds for termination of contractor/subcontractor services.

General Requirements

- Contractors/subcontractors will manage, store, transport, and use oil, hazardous materials, and wastes in accordance with all applicable local, state, and federal laws and regulations, and consistent with these requirements.

- At a minimum, contractors/subcontractors will follow best management practices when storing, transporting or using oil, hazardous materials, and wastes.

- At all times contractors/subcontractors will take care not to cause a spill or release of oil or hazardous materials to the environment.

- Contractors/subcontractors will provide and maintain on-site, sufficient spill cleanup and containment supplies (absorbent pads, containment booms, protective clothing/PPE, debris containers, etc.) to facilitate the proper control, cleanup and packaging of releases of oil, hazardous materials, or wastes.

- Contractors/subcontractors will remove all oils, hazardous materials, wastes and unused materials from the work site at the completion of the job. This includes full and partial waste material containers such as, but not limited to, rags, gloves, trash, scrap material, and empty containers.

NOTE: If large quantities of oil or hazardous materials are involved, written agreements with emergency response contractors may be required.

Storage and Handling Requirements

- Contractors/subcontractors will store only the minimal amount of oil and hazardous material (at each work site) necessary to complete the work.

- Handling and application of pesticides and herbicides will comply with all regulations adopted pursuant to the Maine Pesticide Control Act of 1975, as amended, Title 7 M.R.S., Section 601.

- Oil, hazardous materials and waste materials will be stored in D.O.T. approved containers or approved tanks in areas not considered to be environmentally sensitive.

- Oil, hazardous materials, and waste containers will be kept closed at all times unless material is being transferred.

- Contractors/subcontractors will ensure that all oil, hazardous materials, and waste transfer operations are supervised.

- Oil, hazardous material, and waste containers will not be stored on the ground, but will be stored in a cabinet or on a firm working surface such as a portable trailer bed or other secure decking.

- If at any time a contractor/subcontractor needs to store oil (including but not limited to fuel oil, petroleum products, sludge, or oil refuse) in excess of a total of 1,320 gallons (excluding containers with a capacity less than 55 gallons) at a CMP construction site, U.S. Environmental Protection Agency (USEPA) oil pollution prevention requirements, as well as CMP policies and procedures, must be met. Specifically, a site-specific Spill Prevention, Control, and Countermeasure (SPCC) plan will be developed for the site, and this SPCC Plan will be implemented should any spills occur.

- Storage and handling of flammable and combustible liquids, including gasoline and diesel fuel, will be in accordance with rules adopted pursuant to Title 25 M.R.S. Section 2441 (Fire Prevention and Fire Protection), as amended (See also Code of Maine Rules 16-219 Chapter 317). These regulations include, but are not limited to, requirements relating to bonding and grounding during transfer operations, fire protection, storage quantity limitations, and spacing and location.

- All gasoline and fuel storage tanks must have secondary containment constructed of an impervious material, and must be capable of holding 110% of the capacity of the primary tank.

- Handling and disposal of hazardous wastes will be in accordance with Maine Department of Environmental Protection (DEP) Hazardous Waste Management rules (Chapters 850 through 858) developed pursuant to Title 38 M.R.S. Section 1301 et. seq., and U.S. Environmental Protection Agency regulations (40 CFR 260 through 272). Handling and disposal of waste oil will be in accordance with DEP Waste Oil Management Rules (Chapter 860) and USEPA regulations (40 CFR 279).

Spill Reporting Requirements

- All spill reporting requirements are the responsibility of the contractor/subcontractor. As required by Title 38 M.R.S. Section 543 and DEP regulations (Chapter 600 4.A. and Chapter 800 4.A.(1)), spills of oil or hazardous materials in any amount and under any circumstances must be reported to the Department (1-800-482-0777) within two hours from the time the spill was discovered.

- As required by the Federal Clean Water Act (40 CFR Part 110.4), a discharge of oil "which causes a sheen upon the surface of the water or adjoining shore line or oily sludge deposits beneath the surface of the water" must be reported within 24 hours to the National Response Center (1-800-424-8802).

- The need to report spills of hazardous materials other than oil to the National Response Center, will be determined by the contractor/subcontractor by consulting the CERCLA list of hazardous substances and reportable quantities (40 CFR Table 302.4). Any spills that involve a "reportable quantity" of any hazardous substance must be reported to the National Response Center by the contractor/subcontractor.

- The contractor/subcontractor must also report all spills immediately to CMP.

Spill Cleanup Requirements

- The contractor/subcontractor is responsible to ensure and oversee immediate and complete cleanup of all spills involving oil, hazardous materials, or waste from its equipment.

- The contractor/subcontractor is responsible for all health and safety issues related to the cleanup of oil, hazardous materials, or waste.

- The contractor/subcontractor is responsible for the proper and timely disposal of all resulting spill debris and spill waste, and for restoring the site to its original condition.

EXHIBIT 9 **JUNE 8, 2020 COLIN CLARK (DEP) LETTER**

STATE OF MAINE
DEPARTMENT OF ENVIRONMENTAL PROTECTION

JANET T. MILLS
GOVERNER

GERALD D. REID
COMMISSIONER

June 8, 2020

Via Email Only

Tom Marcotte
Code Enforcement Officer
Town of Industry
1033 Industry Rd
Industry, ME 04938

RE: Shoreland Zoning and Transmission Lines

Dear Tom:

I write to follow up on your questions regarding shoreland zoning and electric power transmission lines. As you are aware, the Department has adopted, as Chapter 1000 of its rules, *Guidelines for Municipal Shoreland Zoning Ordinances*. State law establishes that each municipality must adopt, administer, and enforce an ordinance that is both consistent with and no less stringent than the Department's Chapter 1000 rules. The Town of Industry adopted a Shoreland Zoning Ordinance, which the Town last updated in 2018. This most recent update was approved by the Department. In responding to your questions and explaining how the Department views the regulation of transmission lines within the shoreland zone, this letter focuses on the Department's interpretation of Chapter 1000. Our understanding, however, is that Industry's Shoreland Zoning Ordinance contains comparable provisions, so this discussion of Chapter 1000 should be helpful to the Town as it applies its ordinance.

I. Transmission Lines Are an Allowed Use in All Shoreland Zoning Districts

Within Chapter 1000, transmission lines, including the associated wires, polls, and towers, are defined as "essential services." Ch. 1000, § 17. Essential services are an allowed use in all shoreland zoning districts. Ch. 1000, Table 1, *Land Uses in the Shoreland Zone*, Row 21. While certain distribution lines are allowed without a permit or with a permit from the code enforcement officer (CEO), Table 1, Row 21(A) and (B), transmission lines are a type of essential service that is allowed with a permit from the planning board. Table 1, Row 21(D).

Chapter 1000 recognizes both the importance of essential services and the fact that often they are linear facilities that run for many miles (e.g., distribution lines, transmission lines, telephone lines, gas pipelines, water lines, and municipal sewer lines). Because of the abundance of wetlands, rivers, streams, and other resources subject to shoreland zoning within the state, these types of linear facilities necessarily must cross the shoreland zone if they are to be exist in Maine. This recognition is reflected in essential services being an allowed use in all shoreland zoning districts.

II. Chapter 1000 Contains Land Use Standards Specific to Essential Services

While Chapter 1000 provides that essential services are allowed in all shoreland zoning districts, this rule also establishes specific standards governing the location of new essential services. One standard requires:

> Where feasible, the installation of essential services shall be limited to existing public ways and existing service corridors.

Ch. 1000, § 15(L)(1). Although distribution lines commonly are located along roads, typically transmission lines are not. The practical result of this requirement, which establishes a preference for co-location of new essential services alongside existing essential services, is that new transmission lines typically are located next to existing transmission lines. To establish a new, standalone transmission corridor within a shoreland zoning district, an applicant must show why co-location is not feasible.

A second standard establishes:

> The installation of essential services, other than road-side distribution lines, is not allowed in a Resource Protection or Stream Protection District, except to provide services to a permitted use within said district, or except where the applicant demonstrates that no reasonable alternative exists. Where allowed, such structures and facilities shall be located so as to minimize any adverse impacts on surrounding uses and resources, including visual impacts.

Ch. 1000, § 15(L)(2). With regard to transmission lines, which typically do not deliver power directly to end users, the effect of this requirement is that applicants must evaluate alternatives and show to the planning board that a reasonable alternative outside the Resource Protection or Stream Protection District does not exist. Chapter 1000 does not define what constitutes a reasonable alternative. Factors such as the environmental impact, availability of land, and cost, are among the types of factors a municipal planning board might consider when evaluating the reasonableness of alternatives. The Department's experience is that when reviewing applications for co-location of a new transmission line alongside an existing line, municipalities traditionally have found co-location to be the preferred alternative.

If an applicant demonstrates that there is no reasonable alternative to locating a new transmission line in a Resource Protection District or Stream Protection District, within those districts the applicant must design the project to minimize the transmission's impact. For example, if a transmission line crosses a wetland that is within a Resource Protection District or stream in a Stream Protection District, a planning board might evaluate, among other things, whether poles are proposed to be located and construction access planned in a way that minimizes the impact to the wetland or stream.

III. Applicability of Other Land Use Standards to Transmission Lines

In addition to the land use standards specific to essential services discussed above, Chapter 1000 contains a number of other standards and you have asked about the potential applicability of several of these to transmission lines. I have elaborated on our prior discussion below.

A. Setbacks

Chapter 1000, § 15(B) contains setback requirements from wetlands and water bodies. These requirements apply to new principal and accessory structures. This section does not apply to transmission lines or the associated poles. Neither fits within the definition of the term "structure." Chapter 1000, § 17 defines "structure" as:

> anything temporarily or permanently located, built, constructed or erected for the support, shelter or enclosure of persons, animals, goods or property of any kind or anything constructed or erected on or in the ground. The term includes structures temporarily or permanently located, such as decks, patios, and satellite dishes. Structure does not include fences; poles and wiring and other aerial equipment normally associated with service drops, including guy wires and guy anchors; subsurface waste water disposal systems as defined in Title 30-A, section 4201, subsection 5; geothermal heat exchange wells as defined in Title 32, section 4700-E, subsection 3-C; or wells or water wells as defined in Title 32, section 4700-E, subsection 8.

This provision excludes several types of development from the definition of structure, including a number of types of development that qualify as essential services. One type of development excluded from the definition of structure is "poles and wiring." This captures electric power lines, whether the wires are for distribution or transmission of electricity, and the poles that support these wires, along with telephone poles and lines and similar cable and internet infrastructure. Another type of development exempt from the definition of structure is "other aerial equipment normally associated with service drops." Together, these exemptions facilitate the delivery of essential services to end users, in the case of electric power, by capturing transmission and distribution lines, as well as service drops.

While the setback requirements in Section 15(B) do not apply to transmission lines and their associated poles, please note, however, that Chapter 1000 does not authorize an applicant to locate poles without regard for the potential impact to shoreland zoning resources. As noted above, within the Resource Protection District and Stream Protection District an applicant must locate transmission facilities to minimize adverse impacts on surrounding resources.

B. Vegetation Clearing and Removal

Chapter 1000, § 15(P) contains requirements governing the clearing and removal of vegetation within the shoreland zone. As noted above, essential services such as transmission lines necessarily will cross shoreland zoning resources. For example, rivers, streams, and wetlands are abundant in Maine and a transmission grid cannot be designed without crossing these resources. A transmission grid also cannot be developed and maintained without vegetation removal. This is recognized in Chapter 1000.

Chapter 1000, § 15(R) exempts certain activities from the clearing and vegetation removal standards in Section 15(P), provided all other applicable requirements are complied with and the removal of vegetation is limited to that which is necessary. One category of exempt activity is:

> The removal of vegetation from the location of allowed structures or allowed uses, when the shoreline setback requirements of Section 15(B) are not applicable.

Ch. 1000, § 15(R)(2).

As discussed above, transmission lines are an allowed use and are not subject to the setback requirements of Section 15(B). They are exempt from the vegetation clearing and removal standards of Section 15(P).

* * *

I hope this discussion is helpful to the Town of Industry and its application of its shoreland zoning ordinance. Please let me know if you any other questions.

Regards,

Colin A. Clark
Shoreland Zoning Coordinator

EXHIBIT 10 FINANCIAL CAPABILITY

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2020

Or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File No. 001-37660

AVANGRID

Avangrid, Inc.
(Exact name of registrant as specified in its charter)

Securities registered pursuant to Section 12(b) of the Act:

New York	**14-1798693**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
180 Marsh Hill Road	
Orange, Connecticut	**06477**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (207) 629-1190

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of exchange on which registered
Common Stock, par value $0.01 per share	AGR	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☒	Accelerated Filer ☐
Non-accelerated Filer	☐	Smaller Reporting Company ☐
Emerging Growth Company	☐	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the Avangrid, Inc.'s voting stock held by non-affiliates, computed by reference to the price at which the common equity was last sold as of the last business day of Avangrid, Inc.'s most recently completed second fiscal quarter (June 30, 2020) was $2,374 million based on a closing sales price of $41.98 per share.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 309,371,591 shares of common stock, par value $0.01, were outstanding as of February 26, 2021.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved.

Designated portions of the Proxy Statement relating to the 2021 Annual Meeting of the Shareholders are incorporated by reference into Part III to the extent described therein.

TABLE OF CONTENTS

GLOSSARY OF TERMS AND ABBREVIATIONS

Unless the context indicates otherwise, references in this Annual Report on Form 10-K to "AVANGRID," the "Company," "we," "our," and "us" refer to Avangrid, Inc. and its consolidated subsidiaries.

2016 Joint Proposal	Joint proposal of NYSEG and RG&E and certain other signatory parties approved by the NYPSC on June 15, 2016, for a three-year rate plan for electric and gas service commencing May 1, 2016.
2020 Joint Proposal	Joint proposal of NYSEG and RG&E and certain other signatory parties approved by the NYPSC on November 19, 2020, for a three-year rate plan for electric and gas service commencing December 1, 2020.
AMI	Automated Metering Infrastructure
AOCI	Accumulated other comprehensive income
ARHI	Avangrid Renewables Holdings, Inc.
ARP	Alternative Revenue Programs
ASC	Accounting Standards Codification
Asnat	Asnat Realty, LLC
Army Corps	U.S. Army Corps of Engineers
ARO	Asset retirement obligation
AVANGRID	Avangrid, Inc.
Bcf	One billion cubic feet
BGC	The Berkshire Gas Company
BGEPA	Bald and Golden Eagle Protection Act
BLM	U.S. Bureau of Land Management
BOEM	U.S. Bureau of Ocean Energy Management
CfDs	Contracts for Differences
CFTC	Commodity Futures Trading Commission
CFIUS	Committee on Foreign Investment in the United States
CL&P	The Connecticut Light and Power Company
CLCPA	Climate Leadership and Community Protection Act
CMP	Central Maine Power Company
CNG	Connecticut Natural Gas Corporation
CPCN	Certificate of Public Convenience and Necessity
CSC	Connecticut Siting Council
DCF	Discounted cash flow
DEEP	Connecticut Department of Energy and Environmental Protection
DE&I	Diversity, Equity and Inclusion
DIMP	Distribution Integrity Management Program
DER	Distributed energy resources
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	Department of Energy
DOER	Massachusetts Department of Energy Resources
DOJ	Department of Justice
DPA	Deferred Payment Arrangements
DPU	Massachusetts Department of Public Utilities
DSIP	Distributed System Implementation Plan
DTh	Dekatherm
EAM	Earnings adjustment mechanism
EDC	Massachusetts electric distribution companies
English Station	Former generation site on the Mill River in New Haven, Connecticut
EPA	Environmental Protection Agency

EPAct 2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
ESA	Endangered Species Act
ESC	Energy Smart Community
ESM	Earnings sharing mechanism
Evergreen Power	Evergreen Power III, LLC
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
FirstEnergy	FirstEnergy Corp.
FPA	Federal Power Act
Gas	Enstor Gas, LLC
GE	General Electric
GenConn	GenConn Energy LLC
GenConn Devon	GenConn's peaking generating plant in Devon, Connecticut
GenConn Middletown	GenConn's peaking generating plant in Middletown, Connecticut
HLBV	Hypothetical Liquidation at Book Value
HQUS	H.Q. Energy Services (U.S) Inc.
Iberdrola	Iberdrola, S.A., which owns 81.5% of the outstanding shares of Avangrid, Inc.
Iberdrola Group	The group of companies controlled by Iberdrola, S.A.
Installed capacity	The production capacity of a power plant or wind farm based either on its rated (nameplate) capacity or actual capacity
IRS	Internal Revenue Service
ISO	Independent system operator
ISO-NE	ISO New England, Inc.
ITC	Investment Tax Credit
Klamath Plant	The Klamath gas-fired cogeneration facility located in the city of Klamath, Oregon
kV	Kilovolts
kWh	Kilowatt-hour
LDC	Local distribution company
LIBOR	London Interbank Offer Rate
LNG	Liquefied natural gas
LUPC	Maine Land Use Planning Commission
MBTA	Migratory Bird Treaty Act
MDEP	Maine Department of Environmental Protection
MEPCO	Maine Electric Power Corporation
Merger	The merger of PNMR with and into Merger Sub on the terms and subject to the conditions set forth in the Merger Agreement, with PNMR continuing as the surviving corporation and as a wholly-owned subsidiary of AVANGRID.
Merger Agreement	Agreement and Plan of Merger, dated as of October 20, 2020, among AVANGRID, PNMR and Merger Sub.
Merger Sub	NM Green Holdings, Inc., a New Mexico corporation and wholly-owned subsidiary of AVANGRID.
MGP	Manufactured gas plants
MHI	Mitsubishi Heavy Industries
MISO	Midcontinent Independent System Operator
MNG	Maine Natural Gas Corporation
MPRP	Maine Power Reliability Program

MPUC	Maine Public Utilities Commission
MtM	Mark-to-market
MW	Megawatts
MWh	Megawatt-hours
NAV	Net asset value
NECEC	New England Clean Energy Connect
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NETOs	New England Transmission Owners
Networks	Avangrid Networks, Inc.
New York TransCo	New York TransCo, LLC.
NGA	Natural Gas Act of 1938
NMPRC	New Mexico Public Regulation Commission
NOL	Net operating loss
Non-GAAP	Financial measures that are not prepared in accordance with U.S. GAAP, including adjusted net income and adjusted earnings per share
NRC	Nuclear Regulatory Commission
NYISO	New York Independent System Operator, Inc.
NYPSC	New York State Public Service Commission
NYSE	New York Stock Exchange
NYSEG	New York State Electric & Gas Corporation
NYSERDA	New York State Energy Research and Development Authority
OATT	Open Access Transmission Tariff
OCI	Other comprehensive income
OSHA	Occupational Safety and Health Act, as amended
PA	Connecticut Public Act
PCB	Polychlorinated Biphenyls
PJM	PJM Interconnection, L.L.C.
PNMR	PNM Resources, Inc.
PPA	Power purchase agreement
PTC	Production tax credit
PUCT	Public Utility Commission of Texas
PUHCA 2005	Public Utility Holding Company Act of 2005
PURA	Connecticut Public Utilities Regulatory Authority
RAM	Rate Adjustment Mechanism
RCRA	Resource Conservation and Recovery Act
RDM	Revenue decoupling mechanism
REC	Renewable Energy Certificate
Renewables	Avangrid Renewables, LLC
REV	Reforming the Energy Vision
RFP	Request for Proposals
RG&E	Rochester Gas and Electric Corporation
ROE	Return on equity
ROU	Right-of-use
RPS	Renewable Portfolio Standards
RTO	Regional transmission organization
SCG	The Southern Connecticut Gas Company
SEC	United States Securities and Exchange Commission
SOX	Sarbanes-Oxley Act
Tax Act	Tax Cuts and Jobs Act of 2017 enacted by the U.S. federal government on December 22, 2017

TEF	Tax equity financing arrangements
TSA	Transmission Service Agreement
UI	The United Illuminating Company
UIL	UIL Holdings Corporation
U.S. GAAP	Generally accepted accounting principles for financial reporting in the United States.
VaR	Value-at-risk
VIEs	Variable interest entities
WECC	Western Electricity Coordinating Council

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains a number of forward-looking statements. Forward-looking statements may be identified by the use of forward-looking terms such as “may,” “will,” “should,” “would,” “could,” “can,” “expect(s),” “believe(s),” “anticipate(s),” “intend(s),” “plan(s),” “estimate(s),” “project(s),” “assume(s),” “guide(s),” “target(s),” “forecast(s),” “are (is) confident that” and “seek(s)” or the negative of such terms or other variations on such terms or comparable terminology. Such forward-looking statements include, but are not limited to, statements about our plans, objectives and intentions, outlooks or expectations for earnings, revenues, expenses or other future financial or business performance, strategies or expectations, or the impact of legal or regulatory matters on business, results of operations or financial condition of the business and other statements that are not historical facts. Such statements are based upon the current reasonable beliefs, expectations and assumptions of our management and are subject to significant risks and uncertainties that could cause actual outcomes and results to differ materially. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, without limitation:

- the future financial performance, anticipated liquidity and capital expenditures;
- actions or inactions of local, state or federal regulatory agencies;
- success in retaining or recruiting our officers, key employees or directors;
- changes in amount, timing or ability to complete capital projects;
- adverse developments in general market, business, economic, labor, regulatory and political conditions;
- fluctuations in weather patterns;
- technological developments;
- the impact of extraordinary external events, such as any cyber breaches or other incidents, grid disturbances, acts of war or terrorism, civil or social unrest, natural disasters, pandemic health events or other similar occurrences;
- the impact of any change to applicable laws and regulations affecting operations including those relating to the environment and climate change, taxes, price controls, regulatory approval and permitting;
- our ability to close the proposed Merger (as defined below), the anticipated timing and terms of the proposed Merger, our ability to realize the anticipated benefits of the proposed Merger and our ability to manage the risks of the proposed Merger;
- the COVID-19 pandemic and its impact on business and economic conditions;
- the implementation of changes in accounting standards; and
- other presently unknown unforeseen factors.

Additional risks and uncertainties are set forth under Part I, Item 1A, “Risk Factors” in this Annual Report on Form 10-K. Should one or more of these risks or uncertainties materialize, or should any of the underlying assumptions prove incorrect, actual results may vary in material respects from those expressed or implied by these forward-looking statements. You should not place undue reliance on these forward-looking statements. We do not undertake any obligation to update or revise any forward-looking statements to reflect events or circumstances after the date of this report, whether as a result of new information, future events or otherwise, except as may be required under applicable securities laws. Other risk factors are detailed from time to time in our reports filed with the Securities and Exchange Commission, or SEC, and we encourage you to consult such disclosures.

PART I

Item 1. *Business*

Overview

AVANGRID is one of the leading sustainable energy companies in the United States. Our purpose is to work every day to deliver a more accessible clean energy model that promotes healthier, more sustainable communities. A commitment to sustainability is firmly entrenched in the values and principles that guide AVANGRID, with environmental, social, governance and financial sustainability key priorities driving our business strategy.

AVANGRID has approximately $38 billion in assets and operations in 24 states concentrated in our two primary lines of business - Avangrid Networks and Avangrid Renewables. Avangrid Networks owns eight electric and natural gas utilities, serving approximately 3.3 million customers in New York and New England. Avangrid Renewables owns and operates 8.5 gigawatts of electricity capacity, primarily through wind and solar power, with a presence in 22 states across the United States. AVANGRID supports the achievement of the Sustainable Development Goals approved by the member states of the United Nations, and was named among the World's Most Ethical companies in 2019 and 2020 by the Ethisphere Institute. AVANGRID employs approximately 7,000 people and is listed by Forbes and JUST Capital as one of the 2021 JUST 100, an annual ranking of the most just U.S. public companies. Iberdrola S.A., a corporation *(sociedad anónima)* organized under the laws of the Kingdom of Spain, a worldwide leader in the energy industry, directly owns 81.5% of the outstanding shares of AVANGRID common stock. AVANGRID's primary businesses are described below.

Our direct, wholly-owned subsidiaries include Avangrid Networks, Inc., or Networks, and Avangrid Renewables Holdings, Inc., or ARHI. ARHI in turn holds subsidiaries including Avangrid Renewables, LLC, or Renewables. Networks owns and operates our regulated utility businesses through its subsidiaries, including electric transmission and distribution and natural gas distribution, transportation and sales. Renewables operates a portfolio of renewable energy generation facilities primarily using onshore wind power and also solar, biomass and thermal power. The following chart depicts our current organizational structure.

Through Networks, we own electric generation, transmission and distribution companies and natural gas distribution, transportation and sales companies in New York, Maine, Connecticut and Massachusetts, delivering electricity to approximately 2.3 million electric utility customers and delivering natural gas to approximately 1.0 million natural gas utility customers as of December 31, 2020. The interstate transmission and wholesale sale of electricity by these regulated utilities is regulated by the Federal Energy Regulatory Commission, or FERC, under the Federal Power Act, or FPA, including with respect to transmission rates. Further, Networks' electric and gas distribution utilities in New York, Maine, Connecticut and Massachusetts are subject to regulation by the New York State Public Service Commission, or NYPSC; the Maine Public Utilities Commission, or MPUC; the Connecticut Public Utilities Regulatory Authority, or PURA; and the Massachusetts Department of Public Utilities, or DPU, respectively. Networks strives to be a leader in safety, reliability and quality of service to its utility customers.

Through Renewables, we had a combined wind, solar and thermal installed capacity of 8,499 megawatts, or MW, as of December 31, 2020, including Renewables' share of joint projects, of which 7,734 MW was installed wind capacity. As of December 31, 2020, approximately 67% of the capacity was contracted, for an average period of 9.0 years, and 18% of installed capacity was hedged. Renewables is among the top three largest wind operators in the United States based on installed capacity as of December 31, 2020 and strives to lead the transformation of the U.S. energy industry to a sustainable, competitive, clean energy future. Renewables' installed capacity includes 65 wind farms and four solar facilities in 21 states across the United States.

On October 20, 2020, AVANGRID, PNM Resources, Inc., a New Mexico corporation, or PNMR, and NM Green Holdings, Inc., a New Mexico corporation and wholly-owned subsidiary of AVANGRID, or Merger Sub, entered into an Agreement and Plan of Merger, or Merger Agreement, pursuant to which Merger Sub is expected to merge with and into PNMR, with PNMR surviving the Merger as a direct wholly-owned subsidiary of AVANGRID, or the Merger. Pursuant to the Merger Agreement, each issued and outstanding share of the common stock of PNMR (other than (i) the issued shares of PNMR common stock that are owned by AVANGRID, Merger Sub, PNMR or any wholly-owned subsidiary of AVANGRID or PNMR, which will be automatically cancelled at the time the Merger is consummated and (ii) shares of PNMR common stock held by a holder who has not voted in favor of, or consented in writing to, the Merger who is entitled to, and who has demanded, payment for fair value of such shares) will be converted, at the time the merger is consummated, into the right to receive $50.30 in cash, or Merger Consideration, or approximately $4.3 billion in aggregate consideration. In connection with the Merger, Iberdrola, S.A. has provided the Iberdrola Funding Commitment Letter, pursuant to which Iberdrola has unilaterally agreed to provide to AVANGRID, or arrange the provision to AVANGRID of, funds to the extent necessary for AVANGRID to consummate the Merger, including the payment of the aggregate Merger Consideration. On February 12, 2021, the shareholders of PNMR approved the proposed Merger. The Merger is expected to be consummated in the second half of 2021 and is subject to certain conditions including certain regulatory approvals and entry into agreements providing for, and to making filings required to, exit from all ownership interests in the Four Corners Power Plant and certain other customary closing conditions. For additional information, see Note 1 to our consolidated financial statements contained in this Annual Report on Form 10-K.

Further information regarding the amount of revenues from external customers, including revenues by products and services, a measure of profit or loss and total assets for each segment for each of the last three fiscal years is provided in Note 24 to our consolidated financial statements contained in this Annual Report on Form 10-K.

See “Item 7. *Management’s Discussion and Analysis of Financial Condition and Results of Operations*” in this Annual Report for further details.

History

We were incorporated in 1997 as a New York corporation and named Energy East Corporation. In 2008, Iberdrola acquired Energy East Corporation and we changed our name to Iberdrola USA, Inc. In 2013, we completed an internal corporate reorganization to create a unified corporate presence for the Iberdrola brand in the United States, bringing all of its U.S. energy companies under Iberdrola USA, Inc. The internal reorganization resulted in the concentration of our principal businesses in two major subsidiaries: Networks, which holds all of our regulated utilities; and Renewables, which holds our renewable and thermal generation businesses.

On December 16, 2015, we completed the acquisition of UIL Holdings Corporation, or UIL, and changed our name to Avangrid, Inc. Immediately following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AVANGRID, and Iberdrola owned the remaining shares.

Networks

Overview

Networks, a Maine corporation, holds our regulated utility businesses, including electric generation, transmission and distribution and natural gas distribution, transportation and sales. Networks serves as a super-regional energy services and delivery company through the eight regulated utilities it owns directly:

- New York State Electric & Gas Corporation, or NYSEG, which serves electric and natural gas customers across more than 40% of the upstate New York geographic area;
- Rochester Gas and Electric Corporation, or RG&E, which serves electric and natural gas customers within a nine-county region in western New York, centered around Rochester;
- The United Illuminating Company, or UI, which serves electric customers in southwestern Connecticut;
- Central Maine Power Company, or CMP, which serves electric customers in central and southern Maine;
- SCG, which serves natural gas customers in Connecticut;
- CNG, which serves natural gas customers in Connecticut;
- BGC, which serves natural gas customers in western Massachusetts; and
- Maine Natural Gas Corporation, or MNG, which serves natural gas customers in several communities in central and southern Maine.

The demand for electric power and natural gas is affected by seasonal differences in the weather. Demand for electricity in each of the states in which Networks operates tends to increase during the summer months to meet cooling load or in winter months for heating load while statewide demand for natural gas tends to increase during the winter to meet heating load.

The following table sets forth certain information relating to the rate base, number of customers and the amount of electricity or natural gas provided by each of Networks' regulated utilities as of and for the year ended December 31, 2020:

Utility	Rate Base(1) (in billions)	Electricity Customers	Electricity Delivered (in MWh)	Natural Gas Customers	Natural Gas Delivered (in DTh)
NYSEG	$ 3.1	907,336	15,209,000	270,204	53,381,000
RG&E	$ 2.1	385,925	6,911,000	319,737	56,165,000
CMP	$ 2.4	646,818	9,046,000	—	—
MNG	$ 0.1	—	—	5,201	1,568,000
UI	$ 1.8	341,269	4,812,000	—	—
SCG	$ 0.6	—	—	206,096	33,434,000
CNG	$ 0.5	—	—	183,446	35,342,000
BGC	$ 0.1	—	—	40,637	9,788,000
Total	**$ 10.7**	**2,281,348**	**35,978,000**	**1,025,321**	**189,678,000**

(1) "Rate base" means the net assets upon which a utility can receive a specified return, based on the carrying value of such assets. The rate base is set by the relevant regulatory authority and typically represents the value of specified property, such as plants, facilities and other investments of the utility. These rate base values have been calculated using the best estimates as of December 31, 2020.

During the last five years, Networks has invested $7.2 billion enhancing its delivery network with greater capacity and improved reliability, environmental security and sustainability, efficiency and automation. Networks continuously improves its grid to accommodate new requirements for advanced metering, demand response and enhanced outage management, while improving its flexibility for the integration and management of distributed energy resources, or DER.

New York

In 2020, the nine hydroelectric plants owned by NYSEG and RG&E generated approximately 120 million kilowatt-hours, or kWh, of clean hydropower, which is enough energy to power approximately 17,000 homes across New York State, assuming an average electricity consumption of 600 kWh per month per customer. See "—Properties—Networks" for more information regarding Networks' electric generation plants.

Networks also holds an approximate 20% ownership interest in the regulated New York TransCo, LLC, or New York TransCo. Through New York TransCo, Networks has formed a partnership with affiliates of Central Hudson Gas and Electric Corporation, Consolidated Edison, Inc., National Grid, plc, and Orange and Rockland Utilities, Inc. to develop a portfolio of interconnected transmission lines and substations to fulfill the objectives of the New York energy highway initiative, a proposal to install up to 3,200 MW of new electric generation and transmission capacity in order to deliver more power generated from upstate New York power plants to downstate New York.

Maine

CMP owns 78% of the Maine Electric Power Corporation, or MEPCO, a single-asset 182-mile 345kV electric transmission line from the Maine/New Brunswick border to Wiscasset, Maine.

In 2018, the New England Clean Energy Connect, or NECEC, transmission project, a joint bid proposed by CMP and Hydro-Québec, was selected by the Massachusetts electric utilities and the Massachusetts Department of Energy Resources, or DOER, in the Commonwealth of Massachusetts's 83D clean energy Request for Proposal, or RFP. The proposed NECEC transmission project includes a 145-mile transmission line linking the electrical grids in Québec, Canada and New England. The project, which has an estimated cost of approximately $1.0 billion, would add 1,200 MW of transmission capacity to supply Maine and the rest of New England with power from reliable hydroelectric generation. As of December 31, 2020, we have spent approximately $180 million on the NECEC project. For further discussion of the NECEC project, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in this Annual Report.

Connecticut

UI is a party to a joint venture with Clearway Energy, Inc., which is an affiliate of Global Infrastructure Partners, pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly-owned subsidiary, GenConn

Energy LLC, or GenConn, operates peaking generation plants in Devon, Connecticut, or GenConn Devon, and Middletown, Connecticut, or GenConn Middletown.

Rate Base

The below rate base values were calculated using the best estimates as of December 31, 2020, 2019 and 2018. The rate base of Networks' regulated utilities for the years indicated below were as follows:

Rate base	**2020**	**2019**	**2018**
		(in millions)	
NYSEG Electric	$ 2,408	$ 2,250	$ 2,067
NYSEG Gas	703	610	585
RG&E Electric	1,566	1,453	1,386
RG&E Gas	492	516	497
Subtotal New York	**5,169**	**4,829**	**4,535**
CMP Dist	982	933	903
CMP Trans	1,448	1,469	1,460
MNG	77	76	71
Subtotal Maine	**2,507**	**2,478**	**2,434**
UI Dist	1,170	1,112	1,035
UI Trans	662	672	592
SCG	588	587	550
CNG	524	538	479
Subtotal Connecticut	**2,944**	**2,909**	**2,656**
BGC	124	136	111
Total	**$ 10,744**	**$ 10,352**	**$ 9,736**

Renewables

The Renewables business, based in Portland, Oregon, is engaged primarily in the design, development, construction, management and operation of generation plants that produce electricity using renewable resources and, with more than 70 renewable energy projects, is one of the leaders in renewable energy production in the United States based on installed capacity. Renewables' primary business is onshore wind energy generation, which represented approximately 90% of Renewables' combined installed capacity as of December 31, 2020. For the year ended December 31, 2020, Renewables produced approximately 18,760,000 MWh of energy through wind power generation. Renewables had a pipeline of approximately 21,200 MW (approximately 16,200 MW - onshore and approximately 5,000 MW - offshore) of future renewable energy projects in various stages of development as of December 31, 2020.

Renewables' growing strategic business is offshore wind. Renewables has access to two lease areas off the coast of the eastern United States that it is developing through Vineyard Wind, LLC, a 50-50 partnership with Copenhagen Infrastructure Partners, or CIP, a fund management company based in Denmark. In total, the lease areas have the potential to generate up to 5,000 MW of renewable energy. Renewables is currently developing two wind projects with CIP in one of the lease areas, which is 166,886 acres. The second lease area, acquired in 2018, is 132,370 acres and located over 16 nautical miles off the coast of Massachusetts.

Vineyard Wind LLC is developing the Vineyard Wind I project, an 800 MW utility-scale offshore wind project located 15 miles off the coast of Massachusetts. The Vineyard Wind I project is expected to generate clean energy for over 400,000 households and businesses in Massachusetts and reduce carbon emissions by over 1.6 million tons per year. The project has 20-year PPA's with the electric distribution companies in Massachusetts with an average price of $88.77/MWh, which represents a price for 50% of the project that starts at $65/MWh and escalates 2.5% annually, and a price for the other 50% of the project that starts at $74/MWh and escalates 2.5% annually. Vineyard Wind LLC is also developing the Park City Wind project, an 804 MW project located in the same lease area as the Vineyard Wind I project, that will deliver clean, reliable energy to the residents of Connecticut through contracts with the electric distribution companies in Connecticut. The project has 20-year PPA's with the electric distribution companies in Connecticut, including UI, with an average price of $79.83/MWh, which is based on a starting price of $62.50 that escalates at 2.5% annually. With respect to the Park City Wind project, Vineyard Wind has agreed to have good faith negotiations to adjust the price if the project benefits from any improvements to the profitability of the project for having access to investments tax credits, or ITCs, in excess of 18%. Both projects are expected to be commissioned in the mid-2020's, subject to permitting and contract negotiation.

Renewables also has rights to a federal offshore wind lease area located more than 27 miles off the coast of North Carolina, which has the potential to generate up to 2,500 MW of renewable energy for Virginia and North Carolina. The lease area was acquired through a competitive federal auction in 2017 and is 122,405 acres.

Typically, Renewables enters into long-term lease agreements with property owners who lease their land for renewable energy projects. Electricity generated at a wind project is then transmitted to customers through long-term agreements with purchasers. There are a limited number of turbine suppliers in the market. Renewables' largest turbine suppliers, Siemens-Gamesa, in which Iberdrola had an 8.1% ownership interest until that was sold in February 2020, and GE Wind, in the aggregate supplied turbines that accounted for 72% of Renewables' installed wind capacity as of December 31, 2020.

To monetize the tax benefits resulting from production tax credits, or PTCs, and accelerated tax depreciation available to qualifying wind energy projects, Renewables has entered into "tax equity" financing structures with third party investors for a portion of its wind farms. Renewables holds two operating wind farms under these structures through limited liability companies jointly owned by one or more third party investors. These investors generally provide an up-front investment and, in some cases, payments over time for their membership interests in the financing structures. In return, the investors receive specified cash distribution allocations and substantially all of the tax benefits generated by the wind farms, until such benefits achieve a negotiated return on their investment. Upon attainment of this target return, the sharing of the cash flows and tax benefits flip, with Renewables receiving substantially all of these amounts thereafter. We also have an option to repurchase the investor's interest within a certain timeframe after the target return is met. Renewables maintains operational and management control over the wind farm businesses, subject to investor approval of certain major decisions. See "—Properties—Renewables" for more information regarding Renewables' wind power generation properties.

Additionally, as part of the Renewables portfolio, Renewables operates two thermal generation facilities in the United States, with 636 MW of combined capacity as of December 31, 2020. Renewables worked closely with the City of Klamath Falls, Oregon to develop the Klamath Plant, which has a current capacity of 536 MW. The Klamath Plant operates by creating two useful forms of energy, electricity and process steam, from a single fuel source of natural gas. In addition, Renewables operates a highly flexible 100 MW Klamath Peaking Plant adjacent to the Klamath Plant, providing customers of Renewables additional capability to meet their peak summer and winter power needs.

In addition to its wind assets, Renewables operates four solar photovoltaic facilities with an installed capacity of 130 MW. The solar photovoltaic facilities produced over 242,000 MWh of renewable energy for the year ended December 31, 2020. Solar accounted for 1.5% of the total renewable energy generation from Renewables in these same periods.

Renewables is pursuing the continued development of a large pipeline of wind energy projects in various regions across the United States. Each site features a range of different atmospheric characteristics that ultimately drive the selection of turbine technology for the proposed project. As part of Renewables' wind resource assessment investigation, critical atmospheric parameters such as mean wind speed, extreme wind speed, turbulence intensity, and mean air density are characterized to represent long-term conditions for over 20 years. The summary wind characteristics are then combined with a terrain, or orography, analysis to assess siting risks in order to mitigate any future operations and maintenance concerns that may arise due to improper turbine siting.

Renewables maintains close relationships with key turbine suppliers, including Siemens-Gamesa, GE, Vestas and others in order to identify the turbine technology that safely delivers the lowest cost of energy for each candidate project in its portfolio. Renewables has deployed the following mix of turbines under this strategy. See "—Properties—Renewables" for more information regarding Renewables' turbine technology.

MFG	Model	Rating	Turbines	MW
Siemens-Gamesa	G83	2.0	60	120
Siemens-Gamesa	G87	2.0	648	1,296
Siemens-Gamesa	G90	2.0	236	472
Siemens-Gamesa	G97	2.0	109	218
Siemens-Gamesa	G114	2.0	321	683
Siemens-Gamesa	G145	4.2/4.5	11	49
Siemens-Gamesa	SWT2.3-93	2.3	44	101
GE	1.5s	1.5	79	119
GE	1.5sle	1.5	955	1,433
GE	1.5sle RP1.62	1.6	217	350
GE	2.3	2.3	84	186
GE	2.52	2.52	128	252
GE	2.5	2.5	9	23
GE	2.82	2.82	8	21
GE	2.85	2.85	76	215
MHI	MWT62/1.0	1.0	45	45
MHI	MWT92/2.4	2.4	167	401
MHI	MWT95/2.4	2.4	124	298
MHI	MWT102/2.4	2.4	1	2
Suzlon	S88	2.1	325	681
Vestas	NM48	0.7	3	2
Vestas	V47	0.7	34	22
Vestas	V82	1.7	98	161
Vestas	V126/3.45	3.45	14	48
Vestas	V136/3.6	3.6	109	392
Vestas	V136/3.8	3.8	38	144
Total			3,943	7,734

Renewables focuses on ensuring solar projects deliver the lowest cost of energy safely. This requires detailed information on first cost, long term performance and reliability of project components including solar panels, trackers and inverters – particularly as technology continues to advance. Renewables relies upon a wide network of experienced solar industry consultants to provide expert advice on project development, performance specifications, manufacturing quality assurance and equipment selection. These consultants range from Tetra Tech Inc. for environmental permitting support, to companies such as DNV GL, Clean Energy Associates, and PI Berlin to advise on energy estimation, equipment performance expectations, and equipment quality audits.

The Renewables meteorology team supports the commercial development of wind and solar energy projects in Renewables' pipeline by performing a wide variety of detailed investigations and analyses to characterize the expected wind and solar energy production from a proposed wind farm or solar plant in its pre-construction phase of development. These investigations include measuring the wind or solar resource with several well-equipped meteorological masts and using energy modeling software packages that characterize the gross energy and relevant losses. For wind projects, state of the art laser-based and acoustic-based remote sensing equipment and computational fluid dynamics modeling software are used. The Renewables fleet of measurement masts consists of approximately 100 wind meteorological towers and 12 solar meteorological stations that are currently in operation. Additionally, a total of six light detecting and ranging and six sonic detecting and ranging remote sensing devices are deployed or available for deployment at sites across the United States to support wind project development. These remote sensing devices allow hub-height wind speed measurement from a ground-based sensor that can be rapidly deployed and moved as the project matures or changes in nature. The resulting pre-construction energy production estimates that utilize these measurements have been shown to be accurate in a multi-year internal study that compares results to actual, operational data at wind plants in a benchmarking analysis. This study provides a critical feedback loop that is used to define methodology requirements for future pre-construction energy production estimates to ensure confidence in project investment. Renewables' commitment to obtaining robust atmospheric measurement is driven by a company culture that values business case confidence and understands the role that accurate meteorological data plays in the pursuit of this goal.

Regulatory Environment and Principal Markets

Federal Energy Regulatory Commission

Among other things, the FERC regulates the transmission and wholesale sales of electricity in interstate commerce and the transmission and sale of natural gas for resale in interstate commerce. Certain aspects of Networks' businesses and Renewables' competitive generation businesses are subject to regulation by the FERC.

Pursuant to the FPA, electric utilities must maintain tariffs and rate schedules on file with the FERC, which govern the rates, terms and conditions for the provision of the FERC-jurisdictional wholesale power and transmission services. Unless otherwise exempt, any person that owns or operates facilities used for the wholesale sale or transmission of power in interstate commerce is a public utility subject to the FERC's jurisdiction. The FERC regulates, among other things, the disposition of certain utility property, the issuance of securities by public utilities, the rates, the terms and conditions for the transmission or wholesale sale of power in interstate commerce, interlocking officer and director positions, and the uniform system of accounts and reporting requirements for public utilities.

With respect to Networks' regulated electric utilities in Maine, New York and Connecticut, the FERC governs the return on equity, or ROE, on all transmission assets in Maine and Connecticut and certain New York TransCo assets in New York. The FERC also oversees the rates, terms and conditions of the transmission of electric energy in interstate commerce, interconnection service in interstate commerce (which applies to independent power generators, for example) and the rates, terms and conditions of wholesale sales of electric energy in interstate commerce. This includes cost-based rates, market-based rates and the operations of regional capacity and electric energy markets in New England administered by an independent entity, ISO New England, Inc., or ISO-NE, and in New York, administered by the New York Independent System Operator, Inc., or NYISO. The FERC approves CMP's, UI's and New York TransCo's regulated electric utilities transmission revenue requirements. Wholesale electric transmission revenues are recovered through formula rates that are approved by the FERC. CMP's, MEPCO's and UI's electric transmission revenues are recovered from New England customers through charges that recover costs of transmission and other transmission-related services provided by all regional transmission owners. NYSEG's and RG&E's electric transmission revenues are recovered from New York customers through charges that recover the costs of transmission and other transmission-related services provided by all transmission owners in New York. Several of our affiliates have been granted authority to engage in sales at market-based rates and blanket authority to issue securities and have also been granted certain waivers of the FERC reporting and accounting regulations available to non-traditional public utilities; however, we cannot be assured that such authorizations or waivers will not be revoked for these affiliates or will be granted in the future to other affiliates.

Pursuant to a series of orders involving the ROE for regionally planned New England electric transmission projects, the FERC established a base-level transmission ROE of 11.14%, as well as providing a 50-basis point ROE adder on Pool Transmission Facilities for participation in the regional transmission organization, or RTO, for New England and a 100-basis point ROE incentive for projects included in the ISO-NE Regional System Plan that were completed and on line as of December 31, 2008. Certain other transmission projects received authorization for incentives up to 125 basis points.

Since 2011, several parties have filed four separate complaints with the FERC against ISO-NE and several New England transmission owners, or NETOs, including UI, CMP and MEPCO, claiming that the current approved base ROE of 11.14% was not just and reasonable, seeking a reduction of the base ROE and a refund to customers for the 15-month refund periods beginning October 1, 2011 (Complaint I), December 27, 2012 (Complaint II), July 31, 2014 (Complaint III) and April 29, 2016 (Complaint IV).). For more information on this matter see Note 14 of our consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K, which information is incorporated herein by reference.

The FERC has the right to review books and records of "holding companies," as defined in the Public Utility Holding Company Act of 2005, or PUHCA 2005, that are determined by the FERC to be relevant to the companies' respective FERC-jurisdictional rates. We are a holding company, as defined in PUHCA 2005.

The FERC has civil penalty authority over violations of any provision of Part II of the FPA, as well as any rule or order issued thereunder. FERC is authorized to assess a maximum civil penalty of $1.3 million per violation for each day that the violation continues. The FPA also provides for the assessment of criminal fines and imprisonment for violations under Part II of the FPA. Pursuant to the Energy Policy Act of 2005, or EPAct 2005, the North American Electric Reliability Corporation, or NERC, has been certified by the FERC as the Electric Reliability Organization for North America responsible for developing and overseeing the enforcement of electric system reliability standards applicable throughout the United States. FERC-approved reliability standards may be enforced by the FERC independently, or, alternatively, by NERC and the regional reliability organizations with frontline responsibility for auditing, investigating and otherwise ensuring compliance with reliability standards, subject to the FERC oversight.

The gas distribution operations of NYSEG, RG&E, SCG, CNG and BGC are subject to the FERC regulation under the Natural Gas Act of 1938, or NGA, with respect to their gas purchases/sales and contracted transportation/storage capacity. FERC has civil penalty authority under the NGA to impose penalties for certain violations of up to $1.3 million per day for violations. FERC also has the authority to order the disgorgement of profits from transactions deemed to violate the NGA and EPAct 2005.

Market Anti-Manipulation Regulation

The FERC and the Commodity Futures Trading Commission, or CFTC, monitor certain segments of the physical and futures energy commodities market pursuant to the FPA, the Commodity Exchange Act and the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, including our businesses' energy transactions and operations in the United States. With regard to the physical purchases and sales of electricity and natural gas, the gathering storage, transmission and delivery of these energy commodities and any related trading or hedging transactions that some of our operating subsidiaries undertake, our operating subsidiaries are required to observe these anti-market manipulation laws and related regulations enforced by the FERC and CFTC. The FERC and CFTC hold substantial enforcement authority, including the ability to assess civil penalties of up to $1.3 million per day per violation, to order disgorgement of profits and to recommend criminal penalties.

State Regulation

Networks' regulated utilities are subject to regulation by the applicable state public utility commissions, including with regard to their rates, terms and conditions of service, issuance of securities, purchase or sale of utility assets and other accounting and operational matters. NYSEG and RG&E are subject to regulation by the NYPSC; CMP and MNG are subject to regulation by the MPUC; UI, SCG and CNG are subject to regulation by the PURA; and BGC is subject to regulation by the DPU. The NYPSC, MPUC and the Connecticut Siting Council, or CSC, exercise jurisdiction over the siting of electric transmission lines in their respective states, and each of the NYPSC, MPUC, PURA and DPU exercise jurisdiction over the approval of certain mergers or other business combinations involving Networks' regulated utilities. In addition, each of the utility commissions has the authority to impose penalties on these regulated utilities, which could be substantial, for violating state utility laws and regulations and their orders. In June 2019, the New York State legislature passed a new law titled the Climate Leadership and Community Protection Act, or CLCPA, which could have significant impacts on the operations of electric and gas utilities in New York. A Climate Action Council has been formed consistent with the CLCPA, and that Council will be providing guidance to New York State in reaching aggressive renewable and emission reduction goals delineated in the CLCPA.

Networks' regulated distribution utilities deliver electricity and/or natural gas to all customers in their service territory at rates established under cost of service regulation. Under this regulatory structure, Networks' regulated distribution utilities file rate cases to recover the cost of providing distribution service to their customers based on its costs and earn a return on their capital investment in utility assets. For more information on our regulated utilities' most recent rate cases and other regulatory matters see Note 5 of our consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K, which information is incorporated herein by reference.

As a result of a restructuring of the utility industry in New York, Maine, Connecticut and Massachusetts, most of Networks' distribution utilities' customers have the opportunity to purchase their electricity or natural gas supplies from third-party energy supply vendors. Most customers in New York, however, continue to purchase such supplies through the distribution utilities under regulated energy rates and tariffs. In Maine, CMP customers can also purchase electric supply from competitive providers, but the majority receive baseline standard offer service that is provided through a MPUC procurement process. Networks' regulated utilities in New York, Connecticut and Massachusetts and MNG purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual approved costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

State public utility commissions may also have jurisdiction over certain aspects of Renewables' competitive generation businesses. For example, in New York, certain Renewables' generation subsidiaries are electric corporations subject to "lightened" regulation by the NYPSC. As such, the NYPSC exercises its jurisdictional authority over certain non-rate aspects of the facilities, including safety, retirements and the issuance of debt secured by recourse to those generation assets located in New York. In Texas, Renewables' operations within the Electric Reliability Council of Texas, or ERCOT, footprint are not subject to regulation by FERC, as they are deemed to operate solely within the ERCOT market and not in interstate commerce. These operations are subject to regulation by the Public Utility Commission of Texas, or PUCT. In California, Renewables' generation subsidiaries are subject to regulation by the California Public Utilities Commission with regard to certain non-rate aspects of the facilities, including health and safety, outage reporting and other aspects of the facilities' operations.

RTOs and ISOs

Networks' regulated electric utilities in New York, Connecticut and Maine, as well as some of Renewables' generation fleet, operate in or have access to organized energy markets, known as RTOs or independent system operators, or ISOs, particularly NYISO and ISO-NE. Each organized market administers centralized bid-based energy, capacity and ancillary services markets pursuant to tariffs approved by the FERC, or in the case of ERCOT, market rules approved by the PUCT. These tariffs and rules dictate how the energy, capacity and ancillary service markets operate, how market participants bid, clear, are dispatched, make bilateral sales with one another, and how entities with market-based rates are compensated. Certain of these markets set prices, referred to as Locational Marginal Prices that reflect the value of energy, capacity or certain ancillary services, based upon geographic locations, transmission constraints and other factors. Each market is subject to market mitigation measures designed to limit the exercise of market power. Some markets limit the prices of the bidder based upon some level of cost justification. These market structures impact the bidding, operation, dispatch and sale of energy, capacity and ancillary services.

The RTOs and ISOs are also responsible for transmission planning and operations within their respective regions. Each of Networks' transmission-owning subsidiaries in New York, Connecticut and Maine has transferred operational control over certain of its electric transmission facilities to its respective ISOs, such as ISO-NE and NYISO.

Environmental, Health and Safety

Permitting and Other Regulatory Requirements

Networks. Similar to Renewables, Networks' distribution utilities in New York, Maine, Connecticut and Massachusetts are subject to numerous federal, state and local laws and regulations in connection with the environmental, health and safety effects of its operations. The distribution utilities of Networks are subject to regulation by the applicable state public utility commission with respect to the siting and approval of electric transmission lines, with the exception of UI, the siting of whose transmission lines is subject to the jurisdiction of the CSC, and with respect to pipeline safety regulations for intrastate gas pipeline operators.

The National Environmental Policy Act, or NEPA, requires that detailed statements of the environmental effect of Networks' facilities be prepared in connection with the issuance of various federal permits and licenses. Federal agencies are required by NEPA to make an independent environmental evaluation of the facilities as part of their actions during proceedings with respect to these permits and licenses.

Under the federal Toxic Substances Control Act, the Environmental Protection Agency, or EPA, has issued regulations that control the use and disposal of Polychlorinated Biphenyls, or PCBs. PCBs were widely used as insulating fluids in many electric utility transformers and capacitors manufactured before the federal Toxic Substances Control Act prohibited any further manufacture of such PCB equipment. Fluids with a concentration of PCBs higher than 500 parts per million and materials (such as electrical capacitors) that contain such fluids must be disposed of through burning in high temperature incinerators approved by the EPA. For our gas distribution companies, PCBs are sometimes found in the distribution system. Networks tests any distribution piping being removed or repaired for the presence of PCBs and complies with relevant disposal procedures, as needed.

Under the federal Resource Conservation and Recovery Act, or RCRA, the generation, transportation, treatment, storage and disposal of hazardous wastes are subject to regulations adopted by the EPA. All of Networks' subsidiaries have complied with the notification and application requirements of present regulations, and the procedures by which the subsidiaries handle, store, treat and dispose of hazardous waste products comply with these regulations.

Before the environmental best practices laws and regulations were implemented in the last quarter of the 20th century, utility companies, including Networks' subsidiaries, often disposed of residues from operations by depositing or burying them on-site or at off-site landfills or other facilities. Typical materials disposed of included coal gasification byproducts, fuel oils, ash and other materials that might contain PCBs or otherwise be hazardous. In recent years it was determined that such disposal practices, under certain circumstances, can cause groundwater contamination.

Renewables. Renewables' projects are subject to numerous federal, state and local environmental review and permitting requirements. Whether a project is sited onshore or offshore dictates the complexity of the permitting framework.

Many states where Renewables' projects are located have laws that require state agencies to evaluate the environmental impacts of a proposed project prior to granting state permits or approvals. Generally, state agencies evaluate similar issues as federal agencies, including the project's impact on wildlife, historic or cultural sites, aesthetics, wetlands and water resources, agricultural operations and scenic areas. States may impose different or additional monitoring or mitigation requirements than federal agencies. Additional approvals may be required for specific aspects of a project, such as stream or wetland crossings, impacts to designated significant wildlife habitats, storm water management and highway department authorizations for oversize loads and state road closings during construction. Permitting approvals related to transmission lines may be required in certain cases.

Renewables' projects also are subject to local environmental and regulatory requirements, including county and municipal land use, zoning, building and transportation requirements. Permitting at the local municipal or county level often consists of obtaining a special use or conditional use permit under a land use ordinance or code, or, in some cases, rezoning is required for a project. Obtaining a permit usually requires that Renewables demonstrate that the project will conform to certain development standards specified under the ordinance so that the project is compatible with existing land uses and protects natural and human environments. Local or state regulatory agencies may require modeling and measurement of permissible sound levels in connection with the permitting and approval of Renewables' projects. Local or state agencies also may require Renewables to develop decommissioning plans for dismantling the project at the end of its functional life and establish financial assurances for carrying out the decommissioning plan.

In addition to permits required under state and local laws, Renewables' projects may be subject to permitting and other regulatory requirements under federal law. For example, if an offshore wind project is sited in federal waters (beyond the 3 nautical mile state jurisdictional line), the project will require approval from the Department of Interior's Bureau of Ocean Energy Management, or BOEM as well as other federal cooperating agencies such as the National Oceanic and Atmospheric Administration's National Marine Fisheries Service, the U.S. Army Corps of Engineers, or Army Corps, the Federal Aviation Administration, the Department of Defense, the U.S. Environmental Protection Agency and the U.S. Coast Guard. If an onshore project is located near wetlands, a permit may be required from the Army Corps, with respect to the discharge of dredged or fill material into the waters of the United States. The Army Corps may also require the mitigation of any loss of wetland functions and values that accompanies the project's activities. Renewables may be required to obtain permits under the federal Clean Water Act for water discharges, such as storm water runoff associated with construction activities, and to follow a variety of best management practices to ensure that water quality is protected and impacts are minimized. Renewables' projects also may be located, or partially located, on lands administered by the U.S. Bureau of Land Management, or BLM. Therefore, Renewables may be required to obtain and maintain BLM right-of-way grants for access to, or operations on, such lands. To obtain and maintain a grant, there must be environmental reviews conducted, a plan of development implemented and a demonstration that there has been compliance with the plan to protect the environment, including measures to protect biological, archeological and cultural resources encountered on the grant.

Renewables' projects may be subject to requirements pursuant to the Endangered Species Act, or ESA, and analogous state laws. For example, federal agencies granting permits for Renewables' projects consider the impact on endangered and threatened species and their habitat under the ESA, which prohibits and imposes stringent penalties for harming endangered or threatened species and their habitats. Renewables' projects also need to consider the Migratory Bird Treaty Act, or MBTA, and the Bald and Golden Eagle Protection Act, or BGEPA, which protect migratory birds and bald and golden eagles and are administered by the U.S. Fish and Wildlife Service. Criminal liability can result from violations of the MBTA and the BGEPA. For example, the U.S. Department of Justice, or DOJ, has previously enforced substantial penalties and mitigation measures against two large wind farm operators, pursuant to which those operators pled guilty to criminal violations of the MBTA.

In addition to regulations, voluntary wind turbine siting guidelines for onshore wind projects established by the U.S. Fish and Wildlife Service, or USFWS, set forth siting, monitoring and coordination protocols that are designed to support wind development in the United States while also protecting both birds and bats and their habitats. These guidelines include provisions for specific monitoring and study conditions which need to be met in order for projects to be in adherence with these voluntary guidelines. Most states also have similar laws. Because the operation of wind turbines may result in injury or fatalities to birds and bats, federal and state agencies often recommend or require that Renewables conduct avian and bat risk assessments prior to issuing permits for its projects. They may also require ongoing monitoring or mitigation activities as a condition to approving a project.

Similarly, BOEM has established survey guidelines for renewable energy development, including avian surveys in coordination with the USFWS. BOEM will use the data from the offshore marine surveys to evaluate the impacts of construction, installation and operation of meteorological towers, buoys, export and inter-array cables, wind turbine generators and supporting structures on physical, biological, and socioeconomic resources, as well as the seafloor and sub-seafloor conditions. The information will be used by BOEM, other federal agencies and potentially affected states in the preparation of National Environmental Policy Act documents, for consultations and other regulatory requirements.

Global Climate Change and Greenhouse Gas Emission Issues

Global climate change and greenhouse gas emission issues continue to receive an increased focus from state governments and the federal government. In November 2010, the EPA published final rules for monitoring and reporting requirements for petroleum and natural gas systems that emit greenhouse gases under the authority of the Clean Air Act beginning in 2011. These regulations apply to facilities that emit greenhouse gases above the threshold level of 25,000 metric tons equivalent per year. SCG and CNG both exceed this threshold and are subject to reporting requirements. The liquefied natural gas, or LNG, facilities owned and/or contracted by SCG and CNG are also subject to the monitoring and reporting requirements under the regulations. Similarly, Networks is subject to reporting requirements under provisions of the greenhouse gases regulations, which regulate electric transmission and distribution equipment that emit sulfur hexafluoride.

We are continuously evaluating the regulatory risks and regulatory uncertainty presented by climate change and greenhouse gas emission. Such concerns could potentially lead to additional rules and regulations as well as requirements imposed through the ratemaking process that impact how we operate our business. We expect that any of Networks' costs for these rules, regulations and requirements would be recovered from customers.

OSHA and Certain Other Federal Safety Laws

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, or OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard and standards administered by other federal as well as state agencies, including the Emergency Planning and Community Right to Know Act and the related implementing regulations require that information be maintained about hazardous materials used or produced in operations of our subsidiaries and that this information be provided to employees, state and local government authorities and citizens.

Management, Disposal and Remediation of Hazardous Substances

We own or lease real property and may be subject to federal, state and local requirements regarding the storage, use, transportation and disposal of petroleum products and toxic or hazardous substances, including spill prevention, control and counter-measure requirements. Project properties and materials stored or disposed thereon may be subject to the federal RCRA, the Toxic Substances Control Act, the Comprehensive Environmental Response, Compensation and Liability Act and analogous state laws. If any of our owned or leased properties are contaminated, whether during or prior to our ownership or operation, we could be responsible for the costs of investigation and cleanup and for any related liabilities, including claims for damage to property, persons or natural resources. Such responsibility may arise even if we were not at fault and did not cause the contamination. In addition, waste generated by our operating subsidiaries is at times sent to third party disposal facilities. If such facilities become contaminated, the operating subsidiary and any other persons who arranged for the disposal or treatment of hazardous substances at those sites may be jointly and severally responsible for the costs of investigation and remediation, as well as for any claims of damages to third parties, their property or natural resources.

In August 2016, a partial consent order was issued by DEEP related to the investigation and remediation of the English Station site. The consent order requires UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. Under the consent order, to the extent that the cost of this investigation and remediation is less than $30 million, UI is required to remit to the State of Connecticut the difference between such cost and $30 million to be applied to a public purpose as determined in the discretion of the Governor of the State of Connecticut, the Attorney General of the State of Connecticut and the Commissioner of DEEP. However, UI is obligated to comply with the consent order even if the cost of such compliance exceeds $30 million. The state may discuss options with UI on recovering or funding any cost above $30 million, such as through public funding or recovery from third parties, however it is not bound to agree to or support any means of recovery or funding. UI has initiated its process to investigate and remediate the environmental conditions within the perimeter of the English Station site pursuant to the consent order.

See information on infrastructure protection and cyber security measures in "Properties" in Item 1 of this Annual Report on Form 10-K.

Customers

Networks delivers natural gas and electricity to residential, commercial and institutional customers through its regulated utilities in New York, Maine, Connecticut and Massachusetts. Networks' customer payment terms are regulated by the states of New York, with respect to NYSEG and RG&E; Maine, with respect to CMP and MNG; Connecticut, with respect to UI, SCG and CNG; and Massachusetts, with respect to BGC, and each of the regulated utilities must provide extended payment arrangements to customers for past due balances. See "—Networks" for more information relating to the customers of Networks.

Renewables sells the majority of its output to large investor-owned utilities, public utilities and other credit-worthy entities. Additionally, Renewables generates and provides power, among other services, to federal and state agencies, institutional retail and joint action agencies. Offtakers typically purchase renewable energy from Renewables through long-term PPAs, allowing Renewables to limit its exposure to market volatility. Approximately 67% of Renewables' wind generating capacity is fully committed under PPAs as of December 31, 2020, with an average duration of 9.0 years. Renewables also delivers thermal output to wholesale customers in the Western United States.

Competition

Networks' regulated utilities do not generally face competition from other companies that transmit and distribute electricity and natural gas. However, demand for electricity and natural gas may be negatively impacted by federal and state legislation mandating that certain percentages of power delivered to end users be produced from renewable resources, such as wind, thermal and solar energy.

Networks faces competition from self-contained micro-grids that integrate renewable energy sources in the areas served by Networks. However, there has been limited development of these micro-grids in Networks' service areas to date, and Networks expects that growth in distributed generation of renewable energy will continue due to financial incentives being provided by federal and state legislation.

Renewables has competitive advantages, including a robust development pipeline, a management team with extensive experience, strong relationships with suppliers and clients, expert regulatory knowledge and brand awareness. However, Renewables faces competition throughout the life cycles of its energy facilities, including during the development phase, in the identification and procurement of suitable sites with high wind resource availability, grid connection capacity and land availability. Renewables also competes with other suppliers in securing long-term PPAs with power purchasers and participates in competitive bilateral and organized energy markets with other energy sources for power that is not sold under PPAs. Competitive conditions may be substantially affected by various forms of energy legislation and regulation considered from time to time by federal, state and local legislatures and administrative agencies.

Properties

Networks

The following table sets forth certain information relating to Networks' electricity generation facilities and their respective locations, type and installed capacity as of December 31, 2020. Unless noted otherwise, Networks owns each of these facilities and all our generating properties are regulated under cost of service regulation.

Operating Company	Facility Location	Facility Type	Installed Capacity (in MW)	Year(s) Commissioned
NYSEG	Newcomb, NY	Diesel Turbine	4.3	1967, 2017
NYSEG	Blue Mountain, NY	Diesel Turbine	2.0	2019
NYSEG	Long Lake, NY	Diesel Turbine	2.0	2019
NYSEG	Eastern New York (6 locations)	Hydroelectric	61.4	1921—1986
RG&E	Rochester, NY (3 locations)	Hydroelectric	57.1	1917—1960

UI is also party to a 50-50 joint venture with certain affiliates of Clearway Energy, Inc. in GCE Holding LLC, whose wholly-owned subsidiary, GenConn, operates two 188 MW peaking generation plants, GenConn Devon and GenConn Middletown, in Connecticut.

The following table sets forth certain operating data relating to the electricity transmission and distribution activities of each of Networks' regulated utilities as of December 31, 2020:

Utility	State	Substations	Transmission Lines (in miles)	Overhead Distribution Lines (in pole miles)	Underground Lines (in miles)	Total Distribution (in miles)
NYSEG	New York	430	4,549	32,228	2,960	35,188
RG&E	New York	156	1,094	5,944	2,960	8,904
CMP	Maine	205	2,952	21,834	1,585	23,419
UI	Connecticut	28	138	2,887	753	3,640
Total		**819**	**8,733**	**62,893**	**8,258**	**71,151**

The following table sets forth certain operating data relating to the natural gas transmission and distribution activities of each of Networks' regulated utilities, as of December 31, 2020:

Utility	State	Transmission Pipeline (in miles)	Distribution Pipeline (in miles)
NYSEG	New York	20	8,382
RG&E	New York	105	8,999
MNG	Maine	2	225
SCG	Connecticut	—	2,492
CNG	Connecticut	—	2,204
BGC	Massachusetts	—	766
Total		**127**	**23,068**

CNG owns and operates an LNG plant which can store up to 1.2 Bcf of natural gas and can vaporize up to 100,000 Dth per day of LNG to meet peak demand. SCG has contract rights to and operates a similar plant, which is owned by an affiliate that can also store up to 1.2 Bcf of natural gas. SCG's LNG facilities can vaporize up to 82,000 Dth per day of LNG to meet peak demand. SCG and CNG have also contracted for 20.6 Bcf of storage with a maximum peak day delivery capability of 216,000 Dth per day.

Renewables

The following table sets forth Renewables' portfolio of wind projects as of December 31, 2020. Unless noted otherwise, Renewables wholly owns each of these facilities.

Location	Wind Project	Turbines	Total Installed Capacity (MW)	Commercial Operation Date	North American Electric Reliability Corporation (NERC) Region
Arizona	Dry Lake I	30 (Suzlon S88, 2.1 MW)	63	2009	WECC
	Poseidon Wind (1)	15.5 (Suzlon, 2.1 MW)	33	2010	WECC
California	Dillon	45 (Mitsubishi, 1 MW)	45	2008	WECC
	Manzana	126 (GE, 1.5 MW)	188	2011	WECC
	Mountain View III	34 (Vestas V47, 0.66 MW)	22	2020	WECC
	Phoenix Wind Power	3 (Vestas, 0.66 MW)	2	1999	WECC
	Shiloh	100 (GE, 1.5 MW)	150	2006	WECC
	Tule	57 (GE, 2.3 MW)	130	2017	WECC
Colorado	Colorado Green	100 (GE, 1.5 SLE RP1.62 MW)	162	2003	WECC
	Twin Buttes	50 (GE, 1.5 MW)	75	2007	WECC
	Twin Buttes II	30 (Gamesa G114, 2.10 MW); 6 (Gamesa G114, 2.0 MW)	75	2017	WECC
Illinois	Providence Heights	36 (Gamesa G87, 2.0 MW)	72	2008	MRO
	Streator Cayuga Ridge South	150 (Gamesa, 2.0MW)	300	2010	MRO
	Otter Creek	17 (Vestas, 3.8 MW); 4 (Vestas, 3.5 MW)	158	2020	MRO
Iowa	Barton	80 (Gamesa, 2.0 MW)	160	2009	MRO
	Flying Cloud	29 (GE, 1.5 MW)	44	2004	MRO
	New Harvest	50 (Gamesa G87, 2.0W)	100	2012	MRO
	Top of Iowa II	40 (Gamesa G87, 2.0 MW)	80	2008	MRO
	Winnebago I	10 (Gamesa G87, 2.0 MW)	20	2008	MRO
Kansas	Elk River	100 (GE, 1.5 MW)	150	2005	MRO
Massachusetts	Hoosac	19 (GE, 1.5 MW)	29	2012	NPCC
Minnesota	Elm Creek	66 (GE, 1.5 MW)	99	2008	MRO
	Elm Creek II	62 (Mitsubishi, 2.4)	149	2010	MRO
	MinnDakota	100 (GE, 1.5 MW)	150	2008	MRO
	Moraine I	34 (GE, 1.5 MW)	51	2003	MRO
	Moraine II	33 (GE, 1.5 MW)	50	2009	MRO
	Trimont	67 (GE, 1.5 SLE RP1.62 MW)	107	2020	MRO
Missouri	Farmers City	72 (Gamesa G87, 2.0 MW)	144	2009	MRO

Location	Wind Project	Turbines	Total Installed Capacity (MW)	Commercial Operation Date	North American Electric Reliability Corporation (NERC) Region
New Hampshire	Groton	24 (Gamesa G87, 2.0 MW)	48	2012	NPCC
	Lempster	12 (Gamesa G87, 2 MW)	24	2008	NPCC
New Mexico	El Cabo	140 (Gamesa G114, 2.1 MW); 2 (Gamesa G114, 2.0 MW)	298	2017	WECC
	La Joya	76 (GE 2.85, 2.85 MW); 34 (Gamesa G114, 2.6 MW)	304	2021	WECC
New York	Hardscrabble	37 (Gamesa G90, 2.0 MW)	74	2011	NPCC
	Maple Ridge I(2)	70 (Vestas V82, 1.65 MW)	116	2006	NPCC
	Maple Ridge II(2)	27 (Vestas V82, 1.65 MW)	45	2006	NPCC
	Roaring Brook	5 (Gamesa G114, 2.625); 8 (Gamesa G145, 4.5); 3 (Gamesa G145, 4.2)	62	2021	NPCC
North Carolina	Desert Wind	104 (Gamesa G114, 2.0 MW)	208	2016	SERC
North Dakota	Rugby	71 (Suzlon S88, 2.1 MW)	149	2009	MRO
Ohio	Blue Creek	152 (Gamesa G90 – 2.0 MW)	304	2012	RFC
Oregon	Hay Canyon	48 (Suzlon S88, 2.1 MW)	101	2009	WECC
	Klondike I	16 (GE, 1.5 S – 1.5 MW)	24	2001	WECC
	Klondike II	50 (GE, 1.5 SLE RP1.62 MW)	81	2020	WECC
	Klondike III	44 (Siemens, 2.3 MW); 80 (GE, 1.5 SLE, 1.5 MW); 1 (Mitsubishi, 2.4 MW)	224	2007	WECC
	Klondike IIIa	51 (GE, 1.5 MW)	77	2008	WECC
	Leaning Juniper II	74 (GE, 1.5 MW); 42 (Suzlon, 2.1 MW)	199	2011	WECC
	Montague	51 (Vestas, 3.6 MW); 5 (Suzlon, 3.45 MW)	201	2019	WECC
	Pebble Springs	47 (Suzlon, 2.1 MW)	99	2009	WECC
	Star Point	47 (Suzlon, 2.1 MW)	99	2010	WECC
Pennsylvania	Casselman	23 (GE, 1.5 MW)	35	2008	RFC
	Locust Ridge I	13 (Gamesa G87, 2.0)	26	2006	RFC
	Locust Ridge II	50 (Gamesa G87, 2.0 MW)	100	2009	RFC
	South Chestnut	22 (Gamesa, 2.0 MW)	44	2012	RFC
South Dakota	Buffalo Ridge I	24 (Suzlon, 2.1 MW)	50	2009	MRO
	Buffalo Ridge II	105 (Gamesa G87, 2.0 MW)	210	2010	MRO
	Coyote Ridge (3)	35 (GE, 2.52 MW); 4 (GE, 2.3 MW)	20	2019	MRO
	Tatanka Ridge (3)	1 (GE, 2.3 MW); 4 (GE, 2.3 MW)	23	2021	MRO
Texas	Baffin	101 (Gamesa G97, 2.0 MW)	202	2015	TRE
	Barton Chapel	60 (Gamesa, 2.0 MW)	120	2009	TRE
	Karankawa	93 (GE, 2.52 MW); 22 (GE, 2.3 MW); 9 (GE, 2.5 MW)	307	2019	TRE
	Patriot	58 (Vestas, 3.6 MW); 5 (Vestas, 3.45 MW)	226	2019	TRE
	Peñascal I	84 (Mitsubishi, 2.4 MW)	202	2009	TRE
	Peñascal II	83 (Mitsubishi, 2.4 MW)	199	2010	TRE
Vermont	Deerfield	7 (Gamesa G87, 2.0 MW); 8 (Gamesa G97, 2.0 MW)	30	2017	NPCC
Washington	Big Horn I	133 (GE, 1.5 MW)	200	2006	WECC
	Big Horn II	25 (Gamesa, 2.0 MW)	50	2010	WECC
	Juniper Canyon	62 (Mitsubishi, 2.4 MW)	149	2011	WECC

(1) Jointly owned with Axium; capacity amounts represent only Renewables' share of the wind farm.
(2) Jointly owned with Horizon Wind Energy; capacity amounts represent only Renewables' share of the wind farm.
(3) Jointly owned with WEC Infrastructure; capacity amounts represent only Renewables' share of the wind farm.

Additionally, set forth below are the solar and thermal facilities operated by Renewables as of December 31, 2020. Unless otherwise noted, Renewables owns each facility.

Facility	Location	Type of Facility	Installed Capacity (MW) (3)	Commercial Operation Date
Poseidon Solar (1)	Pinal County, Arizona	Solar	12	2011
San Luis Valley Solar Ranch (2)	Alamosa County, Colorado	Solar	35	2012
Gala Solar	Deschutes County, Oregon	Solar	70	2017
Wy'East Solar	Sherman County, Oregon	Solar	13	2018
Klamath Cogeneration	Klamath Falls, Oregon	Thermal	536	2001
Klamath Peakers	Klamath Falls, Oregon	Thermal	100	2009

(1) Jointly owned with Axium; capacity amounts represent only Renewables' share of the solar project.

(2) Operated pursuant to a sale-and-leaseback agreement.

(3) Previously reported in MWac. Reported in MWdc starting in 2020.

Infrastructure Protection and Cyber Security Measures

We have risk-based security measures in place designed to protect our facilities, assets and cyber-infrastructure, such as our transmission and distribution system.

While we have not had any significant security breaches, a physical security intrusion could potentially lead to theft and the release of critical operating information. In addition to physical security intrusions, a cyber breach could potentially lead to theft and the release of critical operating information or confidential customer information.

To manage these operational risks, pursuant to the cybersecurity risk policy and corporate security policy approved by the AVANGRID board, we have implemented cyber and physical security measures and continue to strengthen our security posture by improving and expanding our physical and cyber security capabilities to protect critical assets.

In an effort to reduce our vulnerability to cyber-attacks, the AVANGRID board appointed a senior officer responsible for security (chief security officer) and we have established a dedicated corporate security office, responsible for improving and coordinating security across the company, who regularly reports to the Audit and Compliance Committee of the AVANGRID board on security matters. We have adopted a comprehensive company-wide physical and cyber security program, which is supported by a governance program to manage, oversee and assist us in meeting our corporate, legal and regulatory responsibilities with regard to the protection of our cyber, physical and information assets.

However, as threats evolve and grow increasingly more sophisticated, we cannot ensure that a potential security breach may not occur or quantify the potential impact of such an event. We continue to invest in technology, processes, security measures and services to predict, detect, mitigate and protect our assets, both physical and cyber. These investments include upgrades to our cyber-infrastructure assets, network architecture and physical security measures, and compliance with emerging industry best practice and regulation. See the risk factor "Security breaches, acts of war or terrorism, grid disturbances or unauthorized access could negatively impact our business, financial condition and reputation" under Item 1A - Risk Factors.

Human Capital Resources

Our industry – like our world – is ever-changing, from the pace of innovation to the priorities of our workforce and stakeholders. Our vision is to be a destination where talented and committed people want to build long-term careers. We support a culture that emphasizes continuous improvement and innovative ideas that challenge the status quo and drive performance. We believe innovation thrives within a healthy and sustainable employee community full of diverse perspectives, which results in better ideas, better products and better service.

To meet the challenges of the future, we are dependent on each of us being safe, empowered, and enabled to bring our unique perspectives and personal best to the workplace every day.

As a purpose-driven organization, we believe sustainable growth requires a diverse and inclusive workplace built on individual accountability and commitment to serving others. We are continuing to invest in initiatives that unleash individual potential, value and reward performance, champion well-being, and foster meaningful connections between each another and the communities we serve.

Demographics

As of December 31, 2020, we employed 7,031 full-time employees, with approximately 49% of our employees represented by a collective bargaining agreement. Virtually all of our employees are full-time. During fiscal year 2020, we hired and onboarded 907 employees. Our voluntary turnover rate was 3.6% in the fiscal year ended December 31, 2020.

Diversity, Equity and Inclusion

Diversity, Equity and Inclusion, or DE&I, is a business imperative for us, as we believe that it is key to our future success. We strive to build and sustain a diverse workforce with a rich mix of differences, inclusive workplaces where each of us feel valued and connected, with equitable opportunities to grow and develop - no matter where we work. We have focused our DE&I initiatives on increasing diverse representation especially in positions of authority, removing barriers, promoting equitable opportunities to grow and develop and building community by establishing tangible pathways for connection with others inside and outside AVANGRID.

During 2020, AVANGRID became a member of the Paradigm for Parity coalition, which is comprised of business leaders, board members and academics committed to addressing the corporate leadership gender gap, and the CEO Action for Diversity & Inclusion, a CEO-driven business commitment to advance diversity and inclusion in workplace. These public initiatives bring business leaders together to commit to specific goals within the workplace – from gender parity to a willingness to have challenging conversations at work. We also established a DE&I Council made up of executive and Business Resource Group leaders to provide steerage and support of our DE&I strategy. We also expanded our Business Resource Groups, adding Pride@ AVANGRID, the AVANGRID African American Council for Excellence (AAACE) and the Hispanic Organization for Leadership and Awareness (¡Hola!). Our Management Committee and their direct reports also engaged in workshops about race and racism facilitated by external training resources. As of December 31, 2020, the approximate demographic breakdowns of our workforce are as follows:

	% of Total	
Ethnicity	**All Employees**	**Senior Leadership**
American Indian or Alaska Native	0.3 %	0.3 %
Asian	2.4 %	2.3 %
Black or African American	6.0 %	2.3 %
Hispanic or Latino	6.3 %	7.0 %
Hawaiian Native or other Pacific Islander	0.0 %	0.0 %
Two or more races	1.1 %	2.0 %
White	76.5 %	70.5 %
Not reported	7.4 %	15.6 %

	Women	**Men**
All Employees	28.0 %	72.0 %
Senior Leadership	29.1 %	70.9 %

Health and Safety

Safety is a core value of AVANGRID. Providing a safe and healthy workplace is our commitment to our employees, communities, customers and investors. Daily emphasis on the importance of a safe workplace – and everyone's role in supporting it – builds employee confidence, motivation and productivity. A safe workplace encourages an environment where creativity and innovation can flourish.

AVANGRID continuously works to embed a safety culture initiative across the company. In addition to the ongoing safety training and awareness programs, we use Safety Excellence Awards and the Spot Recognition Program to recognize exemplary and proactive safety behavior. These programs build critical skills for managers and supervisors to instill and boost engagement with a learning and improving culture for all employees.

A true culture of health and safety is dependent on not only a strong safety program, but also a program that focuses on employee well-being. Healthier employees are at lower risk of injury from industrial exposure and perform work more safely with lower rates of absenteeism. AVANGRID's Health and Well-being program focuses on the physical, emotional, social and financial health of our employees. We provide a wellness portal that all employees and family members can access on their phones to manage their health and wellbeing and participate in activity challenges and other wellbeing activities. We also provided onsite prevention and risk reduction programs, such as biometric screenings and flu shots. Our employees' financial health is equally important so we have developed programs for financial education and advisory services.

During the early stages of the COVID-19 pandemic, AVANGRID formed a cross-functional COVID-19 Crisis Management Team that has been leading and coordinating AVANGRID's overall response. This team leads efforts to develop and monitor mitigation and business continuity plans; track all relevant state and local government guidelines, directives and regulations; develop and adopt work-from-home plans where possible; implement safe working protocols; assess appropriate return-to-office protocols; and provide timely and transparent communications to key stakeholders. In response to the COVID-19 pandemic, AVANGRID provided benefits to its employees to cover the cost of COVID-19 testing, promoted its telehealth benefits, expanded its employee assistance and well-being plans and provided supplemental paid leave for quarantined employees.

Engaging our talent

In 2020, AVANGRID continued its dialogue with employees on their ideas about areas of organizational strength and opportunities to improve our culture and work environment. To understand the employee feedback in response to "The Loop" survey, our annual employee engagement survey, AVANGRID identified engagement leads who were responsible for promoting survey awareness and participation, as well as assisting broader groups of managers and business leaders in the analysis of survey data and in planning specific actions to address the opportunity areas with employees. Action plans were created at both the department and organization levels, and commitments were shared broadly so that employees would know how their feedback was being acted upon and understood. While this is an ongoing effort and there is more to be done, employee engagement increased 9% over the previous year.

Growing our talent

We invest in developing the talent needed to remain at the forefront of innovation and make AVANGRID a destination where talented and committed people want to build long-term careers. We encourage the personal and professional development of our employees through leadership preparation and high potential programs, technical and on-the-job training and learning and education opportunities.

Our employees provide the energy and innovation that drive AVANGRID. That is why it is a priority to attract and develop a highly engaged workforce with quality training and development resources. During 2020, we developed leadership succession and talent management plans to help grow and develop our internal talent to meet future needs, while continuing to develop first-class early career programs to help secure the right people in the right roles with the right skills for a sustainability business. We also deployed modern training and development solutions that leverage new technologies to help fuel our employees' desire to grow and meet the needs of our customers, while enacting leadership and professional development solutions to help enhance skills and capability now and in the future.

Compensation and benefits

AVANGRID's compensation programs are designed to align the compensation of our employees with AVANGRID's performance and are designed to attract, retain and motivate employees to achieve superior results. The structure of our compensation programs balances competitive fixed compensation and variable pay to reward performance by:

- Providing base pay that is consistent with employee positions, skill levels, experience, knowledge and geographic location.
- Evaluating the effectiveness and competitiveness of our executive compensation and benefit programs and benchmarking ourselves against our peers within our industry.
- All employees being eligible for health insurance, paid and unpaid leave, retirement savings plans and life and disability plans.
- Offering a comprehensive set of benefits that allow employees to choose programs that meet their individual needs, including flexible time-off, telemedicine, adoption assistance, back-up child/elder care, and physical, mental and financial wellness programs.

For information on the risks related to our human capital resources, see Item 1A - Risk Factors.

Available Information

Copies of our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed with the SEC may be requested, viewed or downloaded on-line, free of charge, on our website www.avangrid.com. Printed copies of these reports may be obtained free of charge by writing to our Investor Relations Department at 180 Marsh Hill Road, Orange, Connecticut, 06477.

Information about AVANGRID's environmental, social and governance performance and sustainability reporting is also available on our website www.avangrid.com. under the heading "Sustainability." Information contained on our website is not incorporated herein.

The Company may use its website and/or social media outlets, such as Facebook and Twitter, as distribution channels of material company information. Financial and other important information regarding the Company is routinely posted on and accessible through the Company's website at www.avangrid.com, its Facebook page at https://www.facebook.com/Avangrid/ and its Twitter account @AVANGRID. In addition, you may automatically receive email alerts and other information about the Company when you enroll your email address by visiting the Investor Relations section of www.avangrid.com.

Item 1A. Risk Factors

PNMR Merger Risk Factors

There is no assurance when or if the proposed PNMR Merger will be completed.

Completion of the proposed Merger is subject to the satisfaction or waiver of a number of conditions as set forth in the Merger Agreement, including certain regulatory approvals and other customary closing conditions. There can be no assurance that the conditions to completion of the proposed Merger will be satisfied or waived or that other events will not intervene to delay or result in the failure to close the proposed Merger. In addition, each of AVANGRID and PNMR may unilaterally terminate the Merger Agreement under certain circumstances set forth in the Merger Agreement, and AVANGRID and PNMR may agree at any time to terminate the Merger Agreement, even though PNMR's shareholders have already approved the proposed Merger and the other transactions contemplated by the Merger Agreement. The Merger Agreement provides for certain customary termination rights. If we were to terminate the Merger Agreement under certain circumstances, we could incur significant costs (including, without limitation, the payment of the termination fee and out-of-pocket fees and expenses).

AVANGRID and PNMR may be unable to obtain the regulatory approvals required to complete the proposed Merger.

In addition to other conditions set forth in the Merger Agreement, completion of the proposed Merger is conditioned upon the receipt of various state and U.S. federal regulatory approvals including, but not limited to, approval by the Public Utility Commission of Texas, or PUCT, the New Mexico Public Regulation Commission, or NMPRC, the FERC, the Federal Communications Commission, or FCC, the Committee on Foreign Investment in the United States, or CFIUS, the Nuclear Regulatory Commission, or NRC, and under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. AVANGRID and PNMR have made or will make various filings and submissions and are pursuing all required consents, orders and approvals in accordance with the Merger Agreement. These consents, orders and approvals may impose conditions on or require divestitures relating to the divisions, operations or assets of AVANGRID and PNMR or may impose requirements, limitations or costs or place restrictions on the conduct of the combined company's business, and if such consents, orders and approvals require an extended period of time to be obtained, such extended period of time could increase the chance that an event occurs that constitutes a material adverse effect with respect to PNMR and thereby may allow AVANGRID an opportunity not to consummate the proposed Merger. Such extended period of time also may increase the chance that other adverse effects with respect to AVANGRID or PNMR could occur, such as the loss of key personnel.

The Merger Agreement requires AVANGRID and PNMR, among other things, to accept conditions, divestitures, requirements, limitations, costs or restrictions that may be imposed by regulatory entities, subject to the burdensome effect provisions in the Merger Agreement. Such conditions, divestitures, requirements, limitations, costs or restrictions may jeopardize or delay consummation of the proposed Merger, reduce the benefits that may be achieved from the proposed Merger or result in the abandonment of the proposed Merger. Further, no assurance can be given that the required consents, orders and approvals will be obtained or that the required conditions to closing the proposed Merger will be satisfied, and, even if all such consents, orders and approvals are obtained and such conditions are satisfied, no assurance can be given as to the terms, conditions and timing of such consents, orders and approvals.

The announcement and pendency of the proposed Merger could have an adverse effect on AVANGRID's businesses, results of operations, financial condition, cash flows or the market value of AVANGRID's common stock and debt securities.

The announcement and pendency of the proposed Merger could disrupt AVANGRID's businesses, and uncertainty about the effect of the proposed Merger may have an adverse effect on AVANGRID or the combined company following the proposed Merger. AVANGRID's employees may experience uncertainty regarding their roles after the proposed Merger, for example, employees may depart either before or after the completion of the proposed Merger because of such uncertainty and issues relating to the difficulty of coordination or a desire not to remain following the proposed Merger; and the pendency of the proposed Merger may adversely affect AVANGRID's ability to retain, recruit and motivate key personnel. Additionally, the attention of AVANGRID's management may be directed towards the completion of the proposed Merger including obtaining regulatory approvals and other transaction-related considerations and may be diverted from the day-to-day business operations of AVANGRID and matters related to the proposed Merger may require commitments of time and resources that could otherwise have been devoted to other opportunities that might have been beneficial to AVANGRID. Additionally, the Merger Agreement requires AVANGRID to obtain PNMR's consent prior to taking certain specified actions while the proposed Merger is pending. These restrictions may prevent AVANGRID and PNMR from pursuing otherwise attractive business opportunities and executing certain of its business strategies prior to the consummation of the proposed Merger. Further, the proposed Merger may give rise to potential liabilities, including as a result of pending and future shareholder lawsuits relating to the proposed Merger. Any of these matters could adversely affect the businesses of, or harm the results of operations, financial condition or cash flows of AVANGRID and the market value of AVANGRID common stock and debt securities.

AVANGRID will incur substantial transaction fees and costs in connection with the proposed PNMR Merger.

AVANGRID has incurred, and expects to incur additional, material non-recurring expenses in connection with the proposed Merger and consummation of the transactions contemplated by the Merger Agreement. Additional unanticipated costs may be incurred in the course of coordinating the businesses of AVANGRID and PNMR after consummation of the proposed Merger. Even if the proposed Merger is not consummated, AVANGRID may need to pay certain pre-tax costs relating to the proposed Merger incurred prior to the date the proposed Merger was abandoned, such as legal, accounting, financial advisory and filing fees. Additionally, if the proposed Merger is not consummated within the expected timeframe, such delay may materially adversely affect the benefits that AVANGRID may achieve as a result of the proposed Merger and could result in additional pre-tax transaction costs, loss of revenue or other effects associated with uncertainty about the proposed Merger. Satisfying the conditions to, and consummation of, the proposed Merger may take longer than, and could cost more than, AVANGRID expects.

AVANGRID may be unable to integrate PNMR successfully, and AVANGRID may not experience the growth being sought from the proposed Merger.

AVANGRID and PNMR have operated and, until the consummation of the proposed Merger will continue to operate, independently. Coordinating certain aspects of the operations and personnel of PNMR with AVANGRID after the consummation of the proposed Merger will involve complex operational, technological and personnel-related challenges, which may be made more difficult in light of the COVID-19 pandemic. This process will be time-consuming and expensive, may disrupt the businesses of either or both of the companies and may reduce the growth opportunities sought from the Merger. The potential difficulties, and resulting costs and delays, include examples such as:

- managing a larger combined company;
- coordinating corporate and administrative infrastructures;
- unanticipated issues in coordinating information technology, communications, administration and other systems;
- difficulty addressing possible differences in corporate cultures and management philosophies;
- unforeseen and unexpected liabilities related to the proposed Merger or PNMR's business; and
- a deterioration of credit ratings.

While AVANGRID can refuse to consummate the proposed Merger if there is a material adverse effect (as defined in the Merger Agreement) affecting PNMR prior to the consummation of the proposed Merger, certain types of changes do not permit AVANGRID to refuse to consummate the proposed Merger, even if such changes would have a material adverse effect on PNMR. If adverse changes occur but AVANGRID must still consummate the proposed Merger, the market price of AVANGRID common stock may suffer. There can be no assurance that, if the proposed Merger is not consummated, these risks will not materialize and will not materially adversely affect the business and financial results of AVANGRID.

AVANGRID may be materially adversely affected by negative publicity related to the proposed PNMR Merger and in connection with other matters.

From time to time, political and public sentiment in connection with the proposed Merger and in connection with other matters may result in a significant amount of adverse press coverage and other adverse public statements affecting AVANGRID. Adverse press coverage and other adverse statements, whether or not driven by political or public sentiment, may also result in investigations by regulators, legislators and law enforcement officials or in legal claims. Responding to these investigations and lawsuits, regardless of the ultimate outcome of the proceeding, can divert the time and effort of senior management from the management of AVANGRID's businesses. Addressing any adverse publicity, governmental scrutiny or enforcement or other legal proceedings is time consuming and expensive and, regardless of the factual basis for the assertions being made, can have a negative impact on the reputation of AVANGRID, on the morale and performance of its employees and on its relationship with regulators. It may also have a negative impact on AVANGRID's ability to take timely advantage of various business and market opportunities. The direct and indirect effects of negative publicity, and the demands of responding to and addressing it, may have a material adverse effect on AVANGRID's business, financial condition, results of operations and cash flows and the market value of AVANGRID common stock and debt securities.

Failure by PNMR to successfully execute its business strategy and objectives may materially adversely affect the future results of the combined company and, consequently, the market value of AVANGRID's common stock and debt securities.

The success of the Merger will depend, in part, on the ability of PNMR to successfully execute its business strategy, including delivering electricity in a safe and reliable manner, minimizing service interruptions and investing in its transmission and distribution infrastructure to maintain its system, serve its growing customer base with a modernized grid and support energy production. These objectives are capital intensive. If PNMR is not able to achieve these objectives, is not able to achieve these objectives on a timely basis, or otherwise fails to perform in accordance with AVANGRID's expectations, the anticipated benefits of the Merger may not be realized fully or at all, and the Merger may materially adversely affect the results of operations, financial condition and prospects of the combined company and, consequently, the market value of AVANGRID common stock and debt securities.

The market value of AVANGRID common stock could decline if its existing shareholders sell large amounts of its common stock in anticipation of or following the PNMR Merger, and the market prices of AVANGRID common stock and debt securities may be affected by factors following the Merger that are different from those affecting the market prices for AVANGRID's common stock and debt securities prior to the Merger.

Current shareholders of AVANGRID may not wish to continue to invest in the combined company, or may wish to reduce their investment in the combined company, for a number of reasons, which may include loss of confidence in the ability of the combined company to execute its business strategies, to comply with institutional investing guidelines or to increase diversification. If, before or following the Merger, large amounts of AVANGRID common stock are sold, the market price of its common stock could decline. If the Merger is consummated, the risks associated with the combined company may affect the results of operations of the combined company and the market prices of AVANGRID common stock and debt securities following the Merger differently than they affected such results of operations and market prices prior to the Merger. Additionally, the results of operations of the combined company may be affected by additional or different risks than those that currently affect the results of operations of AVANGRID. Any of the foregoing matters could materially adversely affect the market prices of AVANGRID common stock and debt securities following the Merger.

The PNMR Merger may not positively affect AVANGRID's results of operations and/or may cause a decrease in its earnings per share, which may negatively affect the market price of AVANGRID common stock and debt securities.

AVANGRID anticipates that the Merger, if consummated on the terms, will have a positive impact on its consolidated results of operations. This expectation is based on current market conditions and is subject to a number of assumptions, estimates, projections and other uncertainties, including assumptions regarding the results of operations of the combined company after the Merger, and the financing necessary to fund the Merger Consideration. This expectation also assumes that PNMR will perform in accordance with AVANGRID's expectations, and there can be no assurance that this will occur. In addition, AVANGRID may encounter additional transaction costs and costs to manage its investment in PNMR, may fail to realize some or any of the benefits anticipated in the Merger, may be subject to currently unknown liabilities as a result of the Merger, or may be subject to other factors that affect preliminary estimates. As a result, there can be no assurance that the Merger will positively impact AVANGRID's results of operations, and it is possible that the Merger may have an adverse effect, which could be material, on AVANGRID's results of operations, financial condition and prospects and/or may cause its earnings per share to decrease, any of which may materially adversely affect the market price of AVANGRID common stock and debt securities.

AVANGRID may incur additional indebtedness in connection with the PNMR Merger. As a result, it may be more difficult for AVANGRID to pay or refinance its debts or take other actions, and AVANGRID may need to divert cash to fund debt service payments.

AVANGRID may incur significant additional indebtedness to finance the Merger Consideration and related transaction costs. AVANGRID expects to fund all or a portion of the Merger Consideration through sales of its common stock and, possibly, other equity securities, and to the extent it is unable to do so the amount of indebtedness it may incur to finance the Merger and associated transaction costs will likely increase, perhaps substantially. If AVANGRID is required to obtain more debt financing than anticipated to finance the Merger Consideration and associated transaction costs, whether through the issuance of debt securities or borrowings under the committed financing or otherwise, the required regulatory approvals to complete the Merger may be more difficult to obtain and the combined company's credit ratings and ability to service its debt could be materially adversely affected. The increase in AVANGRID's debt service obligations resulting from this additional indebtedness could have a material adverse effect on the results of operations, financial condition and prospects of AVANGRID.

AVANGRID's increased indebtedness could:

- make it more difficult and/or costly for AVANGRID to pay or refinance its debts as they become due, particularly during adverse economic and industry conditions, because a decrease in revenues or increase in costs could cause cash flow from operations to be insufficient to make scheduled debt service payments;
- limit AVANGRID's flexibility to pursue other strategic opportunities or react to changes in its business and the industry sectors in which it operates and, consequently, put AVANGRID at a competitive disadvantage to its competitors that have less debt;
- require a substantial portion of AVANGRID's available cash to be used for debt service payments, thereby reducing the availability of its cash to fund working capital, capital expenditures, development projects, acquisitions, dividend payments and other general corporate purposes, which could harm AVANGRID's prospects for growth and the market price of its common stock and debt securities, among other things;
- result in a downgrade in the credit ratings on AVANGRID's indebtedness, which could limit AVANGRID's ability to borrow additional funds, increase the interest rates under its credit facilities and under any new indebtedness it may incur, and reduce the trading prices of its outstanding debt securities and common stock;
- make it more difficult for AVANGRID to raise capital to fund working capital, make capital expenditures, pay dividends, pursue strategic initiatives or for other purposes;
- result in higher interest expense in the event of increases in interest rates on AVANGRID's current or future borrowings subject to variable rates of interest; and
- require that additional materially adverse terms, conditions or covenants be placed on AVANGRID under its debt instruments.

Based on the current and expected results of operations and financial condition of AVANGRID and its subsidiaries, AVANGRID believes that its cash flow from operations, together with the proceeds from borrowings, issuances of debt securities in the capital markets, distributions from its equity method investments, project financing and equity sales (including tax equity and partnering in joint ventures) will generate sufficient cash on a consolidated basis to make all of the principal and interest payments when such payments are due under AVANGRID's and its current subsidiaries' existing credit facilities, indentures and other instruments governing its outstanding indebtedness and under the indebtedness incurred to fund the Merger Consideration. However, AVANGRID's expectation is subject to numerous estimates, assumptions and uncertainties, and there can be no assurance that AVANGRID will be able to repay or refinance such borrowings and obligations when due. PNMR and its subsidiaries will not guarantee any indebtedness of AVANGRID, nor will any of them have any obligation to provide funds, whether in the form of dividends, loans or otherwise, to enable AVANGRID and its other subsidiaries to make required debt service payments. As a result, the Merger may substantially increase AVANGRID's debt service obligations without any assurance that AVANGRID will receive any cash from PNMR or any of its subsidiaries to assist AVANGRID in servicing its indebtedness or other cash needs.

The Merger will increase our goodwill and other intangible assets.

Following the Merger, we may have a significant amount of goodwill and other intangible assets on our consolidated financial statements that could be subject to impairment based upon future adverse changes in our business or prospects. The impairment of any goodwill and other intangible assets may have a negative impact on our consolidated results of operations.

Any litigation filed against PNMR and the members of the PNMR board of directors could result in the payment of damages following completion of the Merger or prevent or delay completion of the Merger.

In connection with the Merger, purported shareholders of PNMR have filed lawsuits against PNMR and the members of the PNMR board of directors under the federal securities laws, challenging the adequacy of the disclosures made in PNMR's proxy statement in connection with the Merger or otherwise.

The outcome of any such litigation is uncertain. If a dismissal is not granted or a settlement is not reached, the lawsuits could prevent or delay completion of the Merger and result in substantial costs to AVANGRID, including any costs associated with indemnification of PNMR's directors and officers. Additional lawsuits may be filed against PNMR or the directors and officers of PNMR in connection with the Merger. The defense or settlement of any lawsuit or claim that remains unresolved at the time the Merger is consummated may adversely affect the combined company's business, financial condition, results of operations and cash flows.

The impact of severe weather conditions could negatively affect PNMR.

PNMR has large networks of electric transmission and distribution facilities. Weather conditions in the U.S. Southwest region and Texas vary and could contribute to severe weather conditions, such as wildfires or the recent severe winter weather events in Texas, in or near PNMR's service territories. While PNMR may take certain proactive steps to mitigate the risks caused by severe weather conditions, such risks are always present and PNMR could be held liable for damages incurred as a result of severe weather conditions or as a result of wildfires caused, or allegedly caused, by their transmission and distribution systems. In addition, wildfires could cause damage to PNMR's assets that could result in loss of service to customers or make it difficult to supply power in sufficient quantities to meet customer needs. These events could adversely affect PNMR and may materially adversely affect the results of operations, financial condition and prospects of the combined company and, consequently, the market value of AVANGRID's common stock and debt securities.

Costs of decommissioning, remediation and restoration of nuclear and fossil-fueled power plants, as well as reclamation of related coal mines, could exceed the estimates of PNMR as well as the amounts PNMR recovers from its ratepayers, which could negatively impact PNMR.

PNMR has interests in a nuclear power plant, two coal-fired power plants and several natural gas-fired power plants and is obligated to pay its share of the costs to decommission these facilities. PNMR is also obligated to pay for its share of the costs of reclamation of the mines that supply coal to the coal-fired power plants. Likewise, other owners or participants are responsible for their shares of the decommissioning and reclamation obligations and it is important to PNMR that those parties fulfill their obligations. Rates charged by PNMR to its customers, as approved by the NMPRC, include a provision for recovery of certain costs of decommissioning, remediation, reclamation and restoration. The NMPRC has established a cap on the amount of costs for the final reclamation of the surface coal mines that may be recovered from customers. PNMR records estimated liabilities for its share of the legal obligations for decommissioning and reclamation in accordance with GAAP. These estimates include many assumptions about future events and are inherently imprecise. In the event the costs to decommission those facilities or to reclaim the mines serving the plants exceed current estimates, or if amounts are not approved for recovery by the NMPRC, they could materially and adversely affect PNMR and may materially adversely affect the results of operations, financial condition and prospects of the combined company and, consequently, the market value of AVANGRID's common stock and debt securities.

The costs of decommissioning any nuclear or fossil power plant are substantial. PNMR is responsible for all decommissioning obligations related to its entire proportionate interest in Palo Verde Nuclear Generating Station, or PVNGS, San Juan Generating Station, or SJGS, and Four Corners Power Plant, or FCPP, including portions under lease both during and after termination of the leases, other than amounts after the consummation of PNMR's sale of its interest in the Four Corners Power Plant (assuming that transaction closes pursuant to the purchase and sale agreement on December 31, 2024). A delay or termination of the sale of PNMR's interest in the FCPP could have a negative impact on AVAGRID's sustainability reputation.

PNMR maintains trust funds and escrow accounts designed to provide adequate financial resources for decommissioning PVNGS, SJGS and FCPP and for reclamation of the coal mines serving SJGS and FCPP at the end of their expected lives. However, because the funds and accounts grow over time to meet decommissioning and reclamation responsibilities, if the PVNGS, SJGS or FCPP units are decommissioned before their planned dates or the coal mines are shut down sooner than expected, these funds may prove to be insufficient, which may materially adversely affect the results of operations, financial condition and prospects of the combined company and, consequently, the market value of AVANGRID's common stock and debt securities.

There are inherent risks in the ownership and operation of nuclear facilities.

While PNMR does not operate PVNGS, PNMR has an indirect 10.2% undivided interest in PVNGS, including interests in Units 1 and 2 held under leases. PVNGS is subject to environmental, health, and financial risks, including, but not limited to, the ability to obtain adequate supplies of nuclear fuel and water, the ability to dispose of spent nuclear fuel, decommissioning of the plant, securing the facilities against possible terrorist attacks, and unscheduled outages due to equipment failures.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. Events at nuclear facilities of other operators or which impact the industry generally may lead the NRC to impose additional requirements and regulations on all nuclear generation facilities, including PVNGS. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit and to promulgate new regulations that could require significant capital expenditures and/or increase operating costs.

In the event of noncompliance with its requirements, the NRC has the authority to impose a progressively increasing inspection regime that could ultimately result in the shutdown of a unit, civil penalties or both, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved. Increased costs resulting from penalties, a heightened level of scrutiny, and/or implementation of plans to achieve compliance with NRC requirements could adversely affect the financial condition, results of operations, and cash flows of PNMR. Although PNMR has no reason to anticipate a serious nuclear incident at PVNGS, if an incident did occur, it could materially and adversely affect PNMR and may materially adversely affect the results of operations, financial condition and prospects of the combined company and, consequently, the market value of AVANGRID's common stock and debt securities.

Strategic Risk Factors

The success of AVANGRID depends on achieving our strategic objectives, which may be through acquisitions, joint ventures, dispositions and restructurings and failure to achieve these objectives could adversely affect our business, financial condition and prospects.

We are continuously reviewing the alternatives available to ensure that we meet our strategic objectives, which include, among other things, acquisitions, joint ventures, dispositions and restructuring. With respect to potential acquisitions, joint ventures and restructuring activities, we may not achieve expected returns, cost savings and other benefits as a result of various factors including integration and collaboration challenges such as personnel and technology. We also may participate in joint ventures with other companies or enterprises in various markets, including joint ventures where we may have a lesser degree of control over the business operations, which may expose us to additional operational, financial, legal or compliance risks. We also continue to evaluate the potential disposition of assets and businesses that may no longer help us meet our objectives or sell a stake of these assets as a way of maximizing the value of AVANGRID. When we decide to sell assets or a business, we may encounter difficulty in finding buyers or executing alternative exit strategies on acceptable terms in a timely manner, which could delay the accomplishment of our strategic objectives or be on terms less favorable than we anticipated.

We expect to invest in development opportunities in all segments of AVANGRID, but such opportunities may not be successful, projects may not commence operation as scheduled and/or within budget or at all, which could have an adverse effect on our business, financial condition and prospects.

We are pursuing additional development investment opportunities related to all segments of AVANGRID with a particular focus on additional opportunities in electric transmission, renewable energy generation and interconnections to generating resources. The development, construction and expansion of such projects involve numerous risks. Various factors could result in increased costs or result in delays or cancellation of these projects. Risks include regulatory approval processes, permitting, new legislation, citizen referendums or ballot initiatives, economic events, foreign currency risk, environmental and community concerns, negative publicity, design and siting issues, difficulties in obtaining required rights of way, construction delays and cost overruns, including delays in equipment deliveries, particularly of wind turbines or transformers, severe weather, competition from incumbent facilities and other entities, and actions of strategic partners. There may be delays or unexpected developments in completing current and future construction projects. For example, we have spent approximately $180 million and expect to invest approximately $1 billion in our NECEC project. Delays in the regulatory approval and permitting process, new legislation or citizen referendums or ballot initiatives impacting or challenging the necessary approvals and permits, and cost overruns could impact our ability to make these investments and have an adverse effect on the success of the NECEC project and our financial condition and prospects. While most of Renewables' construction projects are constructed under fixed-price and fixed-schedule contracts with construction and equipment suppliers, these contracts provide for limitations on the liability of these contractors to pay liquidated damages for cost overruns and construction delays. These circumstances could prevent Renewables' construction projects from commencing operations or from meeting original expectations about how much electricity it will generate or the returns it will achieve. In addition, for Renewables' projects that are subject to PPAs, substantial delays could cause defaults under the PPAs, which generally require the completion of project construction by a certain date at specified performance levels. A delay resulting in a wind project failing to qualify for federal PTCs or ITCs could result in losses that would be substantially greater than the amount of liquidated damages paid to Renewables.

Regulatory and Legislative Risk Factors

AVANGRID is subject to substantial regulation by federal, state and local regulatory agencies and our business, results of operations and prospects may be adversely affected by legislative or regulatory changes, as well as liability under, or any future inability to comply with, existing or future regulations or requirements.

The operations of AVANGRID are subject to, and influenced by, complex and comprehensive federal, state and local regulation and legislation, including regulations promulgated by state utility commissions and the FERC. This extensive regulatory and legislative framework regulates the industries in which our subsidiaries operate, our business segments, rates for our products and services, financings, capital structures, cost structures, construction, environmental obligations, development and operation of our facilities, acquisition, disposal, depreciation and amortization of facilities and other assets, service reliability, hedging, derivatives transactions and commodities trading.

The federal, state and local political and economic environment has had, and may in the future have, an adverse effect on regulatory decisions with negative consequences for AVANGRID. These decisions may require AVANGRID to cancel, reduce, or delay planned development activities or other planned capital expenditures or investments or otherwise incur costs that we may not be able to recover through rates. We are unable to predict future legislative or regulatory changes, initiatives or interpretations, and there can be no assurance that we will be able to respond adequately or sufficiently quickly to such actions.

AVANGRID is subject to the jurisdiction of various regulatory agencies including, but not limited to, the FERC, the NERC, the CFTC, the DOE and the EPA. Further, Networks' regulated utilities are subject to the jurisdiction of the NYPSC, the MPUC, the New York State Department of Environmental Conservation, the Maine Department of Environmental Protection, the PURA, the CSC, the DEEP and the DPU. These regulatory agencies cover a wide range of business activities, including, among other items the retail and wholesale rates for electric energy, the transmission and distribution of energy, the setting of tariffs and rates including cost recovery clauses, procurement of electricity for Networks' customers, and certain aspects of the siting, construction and transmission and distribution systems. These regulatory agencies have the authority to initiate associated investigations or enforcement actions or impose penalties or disallowances, which could be substantial. Certain regulatory agencies have the authority to review and disallow recovery of costs that they consider excessive or imprudently incurred and to determine the level of return that AVANGRID is permitted to earn on invested capital.

The regulatory process, which may be adversely affected by the political, regulatory, and economic environment in the states we operate in may limit our earnings and does not provide any assurance with respect to the achievement of authorized or other earnings levels. The disallowance of the recovery of costs incurred by us or a decrease in the rate of return that we are permitted to earn on our invested capital could have a material adverse effect on our financial condition. In addition, certain of these regulatory agencies also have the authority to audit the management and operations of AVANGRID and its subsidiaries, which could result in operational changes or adversely impact our financial condition. Such audits and post-audit work require the attention of our management and employees and may divert their attention from other regulatory, operational or financial matters.

AVANGRID's regulated utility operations may not be able to recover costs in a timely manner or at all or obtain a return on certain assets or invested capital through base rates, cost recovery clauses, other regulatory mechanisms or otherwise.

Our regulated utilities are subject to periodic review of their rates and the retail rates charged to their customers through base rates and cost recovery clauses which are subject to the jurisdiction of the NYPSC, MPUC, PURA and DPU, as applicable. New rate proceedings can be initiated by the utilities or the regulators and are subject to review, modification and final authorization and implementation by the regulators. Networks' regulated utilities' business rate plans approved by state utility regulators limit the rates Networks' regulated utilities can charge their customers. The rates are generally designed for, but do not guarantee, the recovery of Networks' regulated utilities' respective cost of service and the opportunity to earn a reasonable rate of Return on Equity, or ROE. Actual costs may increase due to inflation or other factors and exceed levels provided for such costs in the rate plans for Networks' regulated utilities. Utility regulators can initiate proceedings to prohibit Networks' regulated utilities from recovering from their customers the cost of service that the regulators determine to have been imprudently incurred. Networks' regulated utilities defer for future recovery certain costs including major storm costs and environmental costs. Networks' regulated subsidiaries could be denied recovery of certain costs, or deferred recovery pending the next general rate case, including denials or deferrals related to major storm costs and construction expenditures. In some instances, denial of recovery may cause the regulated subsidiaries to record an impairment of assets. If Networks' regulated utilities' costs are not fully and timely recovered through the rates ultimately approved by regulators, our financial condition could be adversely affected.

Current electric and gas rate plans of Networks' regulated utilities include revenue decoupling mechanisms, or RDMs, and the provisions for the recovery of energy costs, including reconciliation of the actual amount paid by such regulated utilities. There is no guarantee that such decoupling mechanisms or recovery and reconciliation mechanism will apply in future rate proceedings.

There are pending challenges at the FERC against New England transmission owners (including UI and CMP) seeking to lower the ROE that these transmission owners are allowed to receive for wholesale transmission service pursuant to the ISO-NE Open Access Transmission Tariff. Reductions to the ROE adversely impact the revenues that Networks' regulated utilities receive from wholesale transmission customers and could have a material effect on our financial condition.

Changes in regulatory and/or legislative policy could negatively impact Networks' transmission planning and cost allocation.

The existing FERC-approved ISO-NE transmission tariff allocates the costs of transmission facilities that provide regional benefits to all customers of participating transmission-owning utilities in New England. The FERC has issued rules requiring all RTOs and transmission owning utilities to make compliance changes to their tariffs and contracts in order to further encourage the construction of transmission for generation, including renewable generation. Changes in RTO tariffs, transmission owners' agreements or legislative policy, or implementation of these new FERC planning rules, could adversely affect our transmission planning and financial condition.

AVANGRID's operating subsidiaries' purchases and sales of energy commodities and related transportation and services expose us to potential regulatory risks that could have a material adverse effect on our business, and financial condition.

Under the EPAct 2005 and the Dodd-Frank Act, AVANGRID is subject to enhanced FERC and CFTC statutory authority to monitor certain segments of the physical and financial energy commodities markets. Under these laws, the FERC and CFTC have promulgated regulations that have increased compliance costs and imposed reporting requirements on AVANGRID. These regulations require our operating subsidiaries to comply with certain margin requirements for our over-the-counter derivative contracts with certain CFTC- or SEC-registered entities that require us to post cash collateral with respect to swap transactions, that could potentially have an adverse effect on our liquidity or our ability to hedge commodity or interest rate risks.

With regard to the physical purchases and sales of energy commodities, the physical trading of energy commodities and any related transportation and/or hedging activities that some of our operating subsidiaries undertake, our operating subsidiaries are required to follow market-related regulations and certain reporting and other requirements enforced by the FERC, the CFTC and the SEC. Additionally, to the extent that operating subsidiaries enter into transportation contracts with natural gas pipelines or transmission contracts with electricity transmission providers that are subject to FERC regulation, the operating subsidiaries are subject to FERC requirements related to the use of such transportation or transmission capacity. Any failure on the part of our operating subsidiaries to comply with the regulations and policies of the FERC, the CFTC or the SEC relating to the physical or financial trading and sales of natural gas or other energy commodities, transportation or transmission of these energy commodities or trading or hedging of these commodities could result in the imposition of significant civil and criminal penalties, which could have a material adverse effect on our business.

The increased cost of purchasing natural gas during periods in which natural gas prices have increased significantly could adversely impact our earnings and cash flow

Our regulated utilities are permitted to recover the costs of natural gas purchased for customers. Under the regulatory body-approved gas cost recovery pricing mechanisms, the gas commodity charge portion of gas rates charged to customers may be adjusted upward on a periodic basis. If the cost of purchasing natural gas increases and Networks' regulated natural gas utilities are unable to recover these costs from its customers immediately, or at all, Networks may incur increased costs associated with higher working capital requirements and/or realize increased costs. In addition, any increases in the cost of purchasing natural gas may result in higher customer bad debt expense for uncollectible accounts and reduced sales volume and related margins due to lower customer consumption.

Climate related proceedings and legislation may result in the alteration of the public utility model in the state we operate in and could materially and adversely impact our business and operations.

Clean energy and emission reduction legislation, proceedings, or executive orders have been issued within New York, Maine, Connecticut and Massachusetts that, among other things, set renewable energy and carbon emission goals and create incentive programs for energy efficiency and renewable energy programs. Additionally, new legislation can require significant change to the natural gas portion of AVANGRID including reduction in usage and restriction of the expansion of natural gas within our territories. We are unable to predict the impact these law and actions may have on the operations of our subsidiaries in New York, Maine, Connecticut and Massachusetts which could have an adverse effect on our business and financial condition.

Renewables relies in part on governmental policies that support utility-scale renewable energy. Any reductions to, or the elimination of, these governmental mandates and incentives or the imposition of additional taxes or other assessments on renewable energy, could adversely impact our growth prospects, our business and financial condition.

Renewables relies, in part, upon government policies that support the development and operation of utility-scale renewable energy projects and enhance the economic feasibility of these projects. The federal government and many state and local jurisdictions have policies or other mechanisms in place, such as tax incentives or Renewable Portfolio Standards, or RPS, that support the sale of energy from utility-scale renewable energy facilities. Federal, state and local governments may review their policies and mechanisms that support renewable energy and take actions that would make them less conducive to the development or operation of renewable energy facilities. Any reductions to, or the elimination of, governmental policies or other mechanisms that support renewable energy or the imposition of additional taxes or other assessments on renewable energy, could result in, among other items, the lack of a satisfactory market for new development, Renewables abandoning the development of new projects, a loss of Renewables' investments in the projects and reduced project returns.

New tariffs imposed on imported goods may increase capital expense in projects and negatively impact expected returns.

Changes in tariffs may affect the final cost of a significant portion of capital expenses in projects, with renewable projects being more exposed. Tariffs have been imposed in the recent years to imports of solar panels, aluminum and steel, among other goods or raw materials. Depending on the timing and contractual terms, tariff changes may have adverse impacts to the buyer of these goods which could affect expected returns on approved projects.

Operational, Environmental, Social and Legal Risk Factors

AVANGRID is subject to numerous environmental laws, regulations and other standards, including rules and regulations with respect to climate change, which could result in increased capital expenditures, operating costs and various liabilities, and could require us to cancel or delay planned projects or limit or eliminate certain operations, all of which could have an adverse effect on our business and financial condition.

AVANGRID is subject to environmental laws and regulations, including, but not limited to, extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, climate change, emissions of greenhouse gases, waste management, hazardous wastes, wildlife mortality and habitat protection, historical artifact preservation, natural resources and health and safety that could, among other things, prevent or delay the development of power generation, power or natural gas transmission, or other infrastructure projects, restrict the output of some existing facilities, limit the availability and use of some fuels required for the production of electricity, require additional pollution control equipment, and otherwise increase costs, increase capital expenditures and limit or eliminate certain operations. There are significant costs associated with compliance with these environmental statutes, rules and regulations, and those costs could be even more significant in the future as a result of new legislation. Violations of current or future laws, rules, regulations or other standards could expose our subsidiaries to regulatory and legal proceedings, disputes with, and legal challenges by, third parties, and potentially significant civil fines, criminal penalties and other sanctions.

Security breaches, acts of war or terrorism, grid disturbances or unauthorized access could negatively impact our business, financial condition and reputation.

Cyber breaches, acts of war or terrorism or grid disturbances resulting from internal or external sources could target our facilities or our information technology systems. In the ordinary course of business, we maintain sensitive customer, employee, financial and system operating information and are required by various laws to safeguard this information. Cyber or physical security intrusions could potentially lead to disabling damage to our facilities or to theft and the release of critical operating information or confidential customer or employee information, which could adversely affect our operations and/or reputation, and could result in significant costs, fines and litigation. Additionally, because our generation and transmission facilities are part of an interconnected regional grid, we face the risk of blackout due to a disruption on a neighboring interconnected system. As threats evolve and grow increasingly more sophisticated, we may incur significant costs to upgrade or enhance our security measures to protect against such risks and we may face difficulties in fully anticipating or implementing adequate preventive measures or mitigating potential harms.

A physical attack on our infrastructure could interfere with our normal business operations and affect our ability to control our transmission and distribution assets. A physical security intrusion could potentially lead to theft and the release of critical operating information and could result in significant costs, fines and litigation. Theft, vandalism or damages to our facilities and equipment can cause significant disruption to operations and can lead to operating losses.

The outbreak of COVID-19 and its impact on business and economic conditions could negatively affect our business, results of operations, financial condition, cash flows and the trading value of our securities.

The scale and scope of the COVID-19 pandemic and the impact on the economy and financial markets could adversely affect our business, financial performance and results of operations. We have not yet experienced a materially adverse impact to our business, results of operations or financial condition, however, given the uncertain scope and duration of the COVID-19 outbreak and its potential effects on our business, we currently cannot predict if there will be materially adverse impacts to our business, results of operations or financial condition in the future. While the situation surrounding COVID-19 remains fluid and its potential impact on AVANGRID is difficult to predict, the continued spread of the virus, availability of a vaccine and actions undertaken by national, regional, and local governments and health officials to contain COVID-19 or treat its effects could: impact customer demand for electricity particularly from businesses, commercial and industrial customers; cause us to experience an increase in costs as a result of our emergency measures, delayed payments from our customers and uncollectable accounts; cause delays and disruptions in the availability and timely delivery of materials and components used in our operations; cause delays and disruptions in the supply chain resulting in disruptions in the commercial operation dates of certain projects and impacting qualification criteria for certain tax credits and potential delay damages in our power purchase agreements; cause deterioration in credit quality of our counterparties, contractors or retail customers that could result in credit losses; cause impairment of goodwill or long-lived assets and impact our ability to develop, construct and operate facilities; result in our inability to meet the requirements of the covenants in our existing credit facilities, including covenants regarding the ratio of indebtedness to total capitalization; cause a deterioration in our financial metrics or the business environment that impacts our credit ratings; cause a delay in the permitting process of certain development projects, affecting the timing of final investment decisions and start of construction dates; cause extended remote work, which could harm productivity, increase cybersecurity risk, strain our business continuity plans, give rise to claims by employees and otherwise negatively impact our business.

If Networks' electricity and natural gas transmission, transportation and distribution systems do not operate as expected, they could require unplanned expenditures, including the maintenance and refurbishment of Networks' facilities, which could adversely affect our business and financial condition.

Networks' ability to operate its electricity and natural gas transmission, transportation and distribution systems is critical to the financial performance of AVANGRID. The ongoing operation of Networks' facilities involves risks customary to the electric and natural gas industry that include the breakdown, failure, loss of use or destruction of Networks' facilities, equipment or processes or the facilities, equipment or processes of third parties due to natural disasters, war or acts of terrorism, operational and safety performance below expected levels, errors in the operation or maintenance of these facilities and the inability to transport electricity or natural gas to customers in an efficient manner. Any unexpected failure, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures, accident, failure of major equipment, shortage of or inability to acquire critical replacement or spare parts could result in reduced profitability, impacted cash flows, harm to our reputation or result in regulatory penalties.

Storing, transporting and distributing natural gas involves inherent risks that could cause us to incur significant costs that could adversely affect our business, financial condition and reputation.

There are inherent hazards and operational risks in gas distribution activities, such as leaks, explosions and mechanical problems that could cause the loss of human life, significant damage to property, environmental pollution and impairment of operations. The location of pipelines and storage facilities near populated areas could increase the level of damages resulting from these risks. These incidents may subject us to litigation and administrative proceedings that could result in substantial monetary judgments, fines or penalties and damage to our reputation.

If Renewables' equipment is not available for operation, Renewables projects' electricity generation and the revenue generated from its projects may fall below expectations and adversely affect our financial condition.

The revenues generated by Renewables' facilities depend upon the ability to maintain the working order of its projects. A natural disaster, severe weather, accident, failure of major equipment, failure of equipment supplier or shortage of or acquire critical replacement of spare parts not held in inventory or maintenance services, including the failure of interconnection to available electricity transmission or distribution networks, could damage or require Renewables to shut down its turbines, panels or related equipment and facilities, leading to decreases in electricity generation levels and revenues.

Renewables' ability to generate revenue from renewable energy facilities depends on interconnecting utility and/or RTO rules, policies, procedures and FERC tariffs that do not present restrictions to renewable project operations which could adversely impact our operations and financial condition.

If a transmission network connected to one or more generating facilities experiences outages or curtailments caused by interconnecting utility and/or RTO, the affected projects may lose revenue. In addition, certain Renewables' generation facilities have agreements that may allow for economic curtailment by off-taker, which could negatively impact revenues. Furthermore, economic congestion on the transmission grid (for instance, a negative price difference between the location where power is put on the grid by a project and the location where power is taken off the grid by the project's customer) in certain of the bulk power markets in which Renewables operates may occur and its businesses may be responsible for those congestion costs. Similarly, negative congestion costs may require that the projects either not participate in the energy markets or bid and clear at negative prices which may require the projects to pay money to operate each hour in which prices are negative. If such businesses were liable for such congestion costs or if the projects are required to pay money to operate in any given hour when prices are negative, then our financial results could be adversely affected. Additionally, we are obligated to pay the FERC Tariff price, which can be adjusted from time to time, for Renewables' facilities interconnection agreements even if the project has been curtailed.

AVANGRID's subsidiaries do not own all the land on which their projects are located and our rights may be subordinate to the rights of lienholders and leaseholders, which could have an adverse effect on their business and financial condition.

Existing and future projects may be located on land occupied under long-term easements, leases and rights of way. The ownership interests in the land subject to these easements, leases and rights of way may be subject to mortgages securing loans or other liens and other easements, lease rights and rights of way of third parties that were created previously. As a result, some of these real property rights be subordinate to the rights of these third parties, and the rights of our operating subsidiaries to use the land on which their projects are, or will be, located and their projects' rights to such easements, leases and rights of way could be lost or curtailed.

AVANGRID and our subsidiaries face risks of strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms which could have an adverse effect on our business and financial condition.

The majority of employees at Networks' facilities are subject to collective bargaining agreements with various unions. Unionization activities, including votes for union certification, could occur among non-union employees. If union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strike or disruption, our subsidiaries could experience reduced power generation or outages if replacement labor is not procured. The ability to procure such replacement labor or the ability to negotiate future collective bargaining agreements on commercially reasonable terms is uncertain.

Advances in technology and rate design initiatives could impair or eliminate AVANGRID's competitive advantage or could result in customer defection, which could have an adverse effect on our growth prospects, business and financial condition.

Legislative and regulatory initiatives designed to reduce greenhouse gas emissions or limit the effects of global warming and overall climate change has increased the development of new technologies for renewable energy, energy efficiency and investment to make those technologies more efficient and cost effective. There is a potential that new technology or rate design incentives could adversely affect the demand for services of our regulated subsidiaries thus impacting our revenues, such as distributed generation. Such emergence of alternative energy supply can result in customers relying on the power grid for limited use or completely abandoning the grid, which is known as customer defection. Similarly, future investments in Networks could be impacted if adequate rate making does not fully contemplate the characteristics of an integrated reliable grid from a unified perspective, regardless of customer disconnection. The interoperability, integration and standard connection of these distributed energy devices and systems could place a burden on the system of Networks' operating subsidiaries, without adequately compensating them. The technology and techniques used in the production of electricity from renewable sources are constantly evolving and becoming more complex. In order to maintain its competitiveness and expand its business, Renewables must adjust to changes in technology effectively and in a timely manner, which could impact our cash flow and/or reduce our profitability.

Business and Market Risk Factors

AVANGRID's operations and power production may fall below expectations due to the impact of natural events, which could adversely affect our financial condition and reputation.

Weather conditions influence the supply and demand for electricity, natural gas and other fuels and affect the price of energy and energy-related commodities. Severe weather can result in power outages, bodily injury and property damage or affect the availability of fuel and water. Many of our facilities could be at greater risk of damage should climate change produce unusual variations in temperature and weather patterns, resulting in more intense, frequent and extreme weather events and conditions.

Recoverability of additional costs associated with restoration and/or repair of regulated utilities facilities is defined within their respective rate decision. Regulatory agencies have the authority to review and disallow recovery of costs that they consider excessive or imprudently incurred. Reliability metrics may be negatively affected resulting in a potential negative rate adjustment or other imposed penalty. Our regulated utilities are subject to adverse publicity focused on the reliability of their distribution services and the speed with which they are able to respond to electric outages, natural gas leaks and similar interruptions caused by storm damage or other unanticipated events. Adverse publicity of this nature could harm our reputations and the reputations of our subsidiaries. Renewables can incur damage to wind or solar equipment, either through natural events such as lightning strikes that damage blades or in-ground electrical systems used to collect electricity from turbines or panels; or may experience production shut-downs or delayed restoration of production during extreme weather conditions resulting from, among other things, icing on the blades or restricted access to sites.

If weather conditions are unfavorable or below production forecasts, Renewables projects' electricity generation and the revenue generated from its projects may fall below expectations and have an adverse effect on financial condition.

Changing weather patterns or lower than expected wind or solar resource could cause reductions in electricity generation at Renewables' projects, which could negatively affect revenues. These events could vary production levels significantly from period to period, depending on the level of available resources. To the extent that resources are not available at planned levels, the financial results from these facilities may be less than expected. Changing weather patterns could also degrade equipment, components, and/or shorten interconnection and transmission facilities' useful lives or increase maintenance costs.

Lower prices for other fuel sources may reduce the demand for wind and solar energy development, which could adversely affect Renewables' growth prospects and financial condition.

Wind and solar energy demand is affected by the price and availability of other fuels, including nuclear, coal, natural gas and oil, as well as other sources of renewable energy. To the extent renewable energy, particularly wind and solar, becomes less cost-competitive due to reduced government targets, increases in the costs, new regulations, incentives that favor other forms of energy, cheaper alternatives or otherwise, demand for renewable energy could decrease.

There are a limited number of purchasers of utility-scale quantities of electricity, which exposes Renewables' utility-scale projects to additional risk that could have an adverse effect on its business.

Since the transmission and distribution of electricity is highly concentrated in most jurisdictions, there are a limited number of possible purchasers for utility-scale quantities of electricity in a given geographic location, including transmission grid operators, state and investor-owned power companies, public utility districts and cooperatives. As a result, there is a concentrated pool of potential buyers for electricity generated by Renewables' businesses, which may restrict our ability to negotiate favorable terms under new PPAs and could impact our ability to find new customers for the electricity generated by our generation facilities should this become necessary. Renewables' PPA portfolio is mostly contracted with low risk regulated utility companies. In the past few years, there has been increased participation from commercial and industrial customers. The higher long-term business risk profile of these companies results in increased credit risk. Furthermore, if the financial condition of these utilities and/or power purchasers deteriorated or the RPS programs, climate change programs or other regulations to which they are currently subject and that compel them to source renewable energy supplies change, demand for electricity produced by Renewables' businesses could be negatively impacted.

The benefits of any warranties provided by the suppliers of equipment for Networks and Renewables' projects may be limited by the ability of a supplier to satisfy its warranty obligations, or if the term of the warranty has expired or has liability limits which could have an adverse effect on our business and financial condition.

Networks and Renewables expect to benefit from various warranties, including product quality and performance warranties, provided by suppliers in connection with the purchase of equipment by our operating subsidiaries. The suppliers may fail to fulfill their warranty obligations, or the warranty may not be sufficient to compensate for all losses or cover a particular defect. In addition, these warranties generally expire within two to five years after the date of equipment delivery or commissioning and are subject to liability limits. If installation is delayed, the operating subsidiaries may lose all or a portion of the benefit of warranty.

Renewables' revenue may be reduced upon expiration or early termination of PPAs if the market price of electricity decreases and Renewables is otherwise unable to negotiate favorable pricing terms which could have a negative effect on our business and financial condition.

Renewables' PPA portfolio primarily has fixed or otherwise predetermined electricity prices for the life of each PPA. A decrease in the market price of electricity could result in a decrease in revenues upon expiry or extension of a PPA. The majority of Renewables' energy generation projects become merchant upon the expiration of a PPA and are subject to market risks unless Renewables can negotiate an extension or replacement contract. If Renewables is not able to secure a replacement contract with equivalent terms and conditions or otherwise obtain prices that permit operation of the related facility on a profitable basis, the affected project may temporarily or permanently cease operations and trigger an asset value impairment.

Our risk management policies cannot fully eliminate the risk associated with some of our operating subsidiaries' commodity trading and hedging activities, which may result in significant losses and adversely impact our financial condition.

Our subsidiaries' commodity trading and hedging activities are inherently uncertain and involve projections and estimates of factors that can be difficult to predict such as future prices and demand for power and other energy-related commodities. In addition, Renewables has exposure to commodity price movements through their "natural" long positions in electricity in addition to proprietary trading and hedging activities. We manage the exposure to risks of such activities through internal risk management policies, enforcement of established risk limits and risk management procedures but they may not be effective and, even if effective, cannot fully eliminate the risks associated with such activities.

Risk Factors Relating to Ownership of Our Common Stock

Iberdrola exercises significant influence over AVANGRID, and its interests may be different from yours. Additionally, future sales or issuances of our common stock by Iberdrola could have a negative impact on the price of our common stock.

Iberdrola owns approximately 81.5% of outstanding shares of our common stock and will be able to exercise significant influence over AVANGRID's policies and affairs, including the composition of our board of directors and any action requiring the approval of our shareholders, including the adoption of amendments to the certificate of incorporation and bylaws and the approval of a merger or sale of substantially all of our assets, subject to applicable law and the limitations set forth in the shareholder agreement to which we and Iberdrola are parties. The directors designated by Iberdrola may have significant authority to effect decisions affecting our capital structure, including the issuance of additional capital stock, incurrence of additional indebtedness, the implementation of stock repurchase programs and the decision of whether or not to declare dividends.

The interests of Iberdrola may conflict with the interests of our other shareholders. For example, Iberdrola may support certain long-term strategies or objectives for us that may not be accretive to shareholders in the short term. The concentration of ownership may also delay, defer or even prevent a change in control, even if such a change in control would benefit our other shareholders, and may make some transactions more difficult or impossible without the support of Iberdrola. This significant concentration of share ownership may adversely affect the trading price for shares of our common stock because investors may perceive disadvantages in owning stock in companies with shareholders who own significant percentages of a company's outstanding stock.

Further, sales of our common stock by Iberdrola or the perception that sales may be made by it could significantly reduce the market price of shares of our common stock. Even if Iberdrola does not sell a large number of shares of our common stock into the market, its right to transfer such shares may depress the price of our common stock. Furthermore, pursuant to the shareholder agreement, Iberdrola is entitled to customary registration rights of our common stock, including the right to choose the method by which the common stock is distributed, a choice as to the underwriter and fees and expenses to be borne by us. Iberdrola also retains preemptive rights to protect against dilution in connection with issuances of equity by us. If Iberdrola exercises its registration rights and/or its preemptive rights, the market price of shares of our common stock may be adversely affected. Additionally, being a controlled company, relevant risks materializing at the ultimate parent level could have a negative impact on our share price, financial condition, credit ratings or reputation.

We have elected to take advantage of the "controlled company" exemption to the corporate governance rules for NYSE-listed companies, which could make shares of our common stock less attractive to some investors or otherwise harm our stock price.

Under the rules of the NYSE, a company in which over 50% of the voting power is held by an individual, a group or another company is a "controlled company" and may elect to take advantage of certain exemptions to the corporate governance rules for NYSE-listed companies. AVANGRID has elected to take advantage of these exemptions and, as a controlled company, is not required to have a majority of its board of directors be independent directors, a compensation committee, or to have such committees be composed entirely of independent directors, and a nominating and corporate governance committee, or to have such committee composed entirely of independent directors. Because we are a "controlled company," you will not have the same protections afforded to shareholders of companies that are subject to all the corporate governance requirements of the NYSE without regard to the exemptions available for "controlled companies." Our status as a "controlled company" could make our shares of common stock less attractive to some investors or otherwise harm our stock price.

Our dividend policy is subject to the discretion of our board of directors and may be limited by our debt agreements and limitations under New York law.

Although we currently anticipate paying a regular quarterly dividend, any such determination to pay dividends is at the discretion of our board of directors and dependent on conditions such as our financial condition, earnings, legal requirements, including limitations under New York law and other factors the board of directors deem relevant. Our board of directors may, in its sole discretion, change the amount or frequency of dividends or discontinue the payment of dividends entirely. For these reasons, investors may not be able to rely on dividends to receive a return on their investments.

AVANGRID may be unable to meet our financial obligations and to pay dividends on our common stock if our subsidiaries are unable to pay dividends or repay loans from us.

We are a holding company and, as such, have no revenue-generating operations of our own. We are dependent on dividends and the repayment of loans from our subsidiaries and on external financings to provide the cash necessary to make future investments, service debt we have incurred, pay administrative costs and pay dividends. Our subsidiaries are separate legal entities and have no independent obligation to pay dividends. Our regulated utilities are restricted by regulatory decision from paying us dividends unless a minimum equity-to-total capital ratio is maintained. The future enactment of laws or regulations may prohibit or further restrict the ability of our subsidiaries to pay upstream dividends or to repay funds. In addition, in the event of a subsidiary's liquidation or reorganization, our right to participate in a distribution of assets is subject to the prior claims of the subsidiary's creditors. As a result, our ability to pay dividends on our common stock and meet our financial obligations is reliant on the ability of our subsidiaries to generate sustained earnings and cash flows and pay dividends to and repay loans from us.

General Risk Factors

If we are unable to implement and maintain effective internal control over financial reporting in the future, investors may lose confidence in the accuracy and completeness of our financial reports and the trading price of our common stock may be negatively affected.

As a public company, we are subject to reporting, disclosure control and other obligations in accordance with applicable laws and rules adopted, and to be adopted, by the SEC and the NYSE such as the requirement that our management to report on the effectiveness of our internal control over financial reporting and our independent registered public accounting firm to attest to the effectiveness of our internal controls. Our management and other personnel devote a substantial amount of time to these compliance activities, and if we are not able to comply with these requirements in a timely manner or if we are unable to conclude that our internal control over financial reporting is effective, our ability to accurately report our cash flows, results of operations or financial condition could be inhibited and additional financial and management resources could be required. Any failure to maintain internal control over financial reporting or if our independent registered public accounting firm determines the we have a material weakness or significant deficiency in our internal control over financial reporting, could cause investors to lose confidence in the accuracy and completeness of our financial reports, a decline in the market price of our common stock, or subject us to sanctions or investigations by the NYSE, the SEC or other regulatory authorities. Failure to remedy any material weakness or significant deficiency in our internal control over financial reporting, or to implement or maintain other effective control systems required of public companies, could also restrict our future access to the capital markets and reduce or eliminate the trading market for our common stock.

Changes in tax laws, as well as judgments and estimates used in the determination of tax-related asset and liability amounts, could adversely affect our financial condition.

Our provision for income taxes and reporting of tax-related assets and liabilities require significant judgments and the use of estimates. Amounts of tax-related assets and liabilities involve judgments and estimates of the timing and probability of recognition of income, deductions and tax credits, including, but not limited to, estimates for potential adverse outcomes regarding tax positions that have been taken and the ability to utilize tax benefit carryforwards, such as net operating loss, or NOL, and tax credit carryforwards. Actual income taxes could vary significantly from estimated amounts due to the future impacts of, among other things, changes in tax laws, regulations and interpretations, our financial performance and results of operations.

Our investments and cash balances are subject to the risk of loss.

Our cash balances and the cash balances at our subsidiaries may be deposited in banks, may be invested in liquid securities such as commercial paper or money market funds or may be deposited in a liquidity agreement in which we are a participant along with other affiliates of the Iberdrola Group. Bank deposits in excess of federal deposit insurance limits would be subject to risks in the counterparty bank. Liquid securities and money market funds are subject to loss of principal, more likely in an adverse market situation, and to the risk of illiquidity.

The cost and availability of capital to finance our business is inherently uncertain and may adversely affect our financial condition.

AVANGRID and its subsidiaries are exposed to an increase in the general level of interest rates and to events, such as the 2008 financial crisis, affecting the capital markets that may increase the cost of capital or restrict its availability. In addition, AVANGRID's performance directly affects its financial strength and credit ratings and therefore its cost of, and ability to attract, capital. Significant increases in the cost of capital, whether caused by economic or capital market conditions or adverse company performance, would adversely impact our financial performance and may make certain potential business opportunities uneconomic. Prolonged inability to access capital would impair our ability to execute our business plan and could impair AVANGRID's ability to meet its financial obligations.

AVANGRID and our subsidiaries are subject to litigation or administrative proceedings, the outcome or settlement of which could adversely affect our business, financial condition and reputation.

AVANGRID and our operating subsidiaries have been and continue to be involved in legal proceedings, administrative proceedings, claims and other litigation that arise in the ordinary course of business. AVANGRID could experience unfavorable outcomes, developments or settlement of claims relating to these proceedings or future proceedings such as judgments for monetary damages, injunctions, unfavorable settlement terms, or denial or revocation of permits or approvals that could adversely impact our business, financial condition and reputation.

AVANGRID is not able to insure against all potential risks which could adversely affect our financial condition.

AVANGRID is exposed to certain risks inherent in our business such as equipment failure, manufacturing defects, natural disasters, terrorist attacks, cyber-attacks and sabotage, as well as affected by international, national, state or local events. Our insurance coverage may not continue to be offered or offered on an economically feasible basis and may not cover all events that could give rise to a loss or claim involving the assets or operations of our subsidiaries.

Pension and post-retirement benefit plans could require significant future contributions to such plan that could adversely impact our business and financial condition.

We provide defined benefit pension plans and other post-retirement benefits administered by our subsidiaries for a significant number of employees, former employees and retirees. Financial market disruptions and significant declines in the market values of the investments held to meet those obligations, discount rate assumptions, participant demographics and increasing longevity, and changes in laws and regulations may require us to make significant contributions to the plans.

AVANGRID and our subsidiaries may suffer the loss of key personnel or the inability to hire and retain qualified employees, which could have an adverse effect on our operations and financial condition.

The operations of AVANGRID depend on the continued efforts of our employees. Retaining key employees and attracting new employees are important to our financial performance and our operations. We cannot guarantee that any member of our management will continue to serve in any capacity for any length of time. In addition, a significant portion of our skilled workforce will be eligible to retire in the next five to ten years. Such highly skilled individuals cannot be quickly replaced due to the technically complex work they perform. This could lead to a loss in productivity and increased recruiting and training costs.

Item 1B. *Unresolved Staff Comments.*

None.

Item 2. *Properties.*

We have included descriptions of the location and general character of our principal physical operating properties by segment in “Item 1. *Business*”, which is incorporated herein by reference. The principal offices of AVANGRID and Networks are located in Orange, Connecticut; Portland, Maine; and Rochester, New York, while Renewables’ headquarters is located in Portland, Oregon. In addition, AVANGRID and its subsidiaries have various administrative offices located throughout the United States. AVANGRID leases part of its administrative and local offices.

The following table sets forth the principal properties of AVANGRID, by location, type, lease or ownership and size as of December 31, 2020:

Location	Type of Facility	Leased/Owned	Size (square feet)
Orange, Connecticut	Office	Owned	127,310
Augusta, Maine	Office	Leased	220,400
Portland, Maine	Office	Leased	15,194
Rochester, New York	Office	Owned	122,494
Portland, Oregon	Office	Leased	63,543

We believe that our office facilities are adequate for our current needs and that additional office space can be obtained if necessary.

Item 3. *Legal Proceedings.*

For information with respect to this item see Notes 14 and 15 of our consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K, which information is incorporated herein by reference.

Item 4. *Mine Safety Disclosures.*

Not applicable.

Information about our Executive Officers

The names and ages of all executive officers of AVANGRID as of February 26, 2021 and a brief account of the business experience during the past five years of each executive officer are as follows:

Name	Age (1)	Title
Dennis V. Arriola	60	Chief Executive Officer
Douglas K. Stuver	57	Senior Vice President – Chief Financial Officer
Scott M. Tremble	41	Senior Vice President – Controller
Alejandro de Hoz García-Bellido	53	President and Chief Executive Officer of Renewables
David T. Flanagan	73	Executive Chairman of CMP
Peter T. Church	48	Senior Vice President – Human Resources & Corporate Administration
Ignacio Estella	51	Senior Vice President – Corporate Development
Robert D. Kump	59	Deputy Chief Executive Officer and President
Carl A. Taylor	56	President and Chief Executive Officer of NYSEG and RG&E
R. Scott Mahoney	55	Senior Vice President – General Counsel and Corporate Secretary
Anthony Marone	57	President and Chief Executive Officer of Networks
Franklyn Reynolds	53	President and Chief Executive Officer of UIL

(1) Age as of December 31, 2020.

Dennis V. Arriola. Mr. Arriola was appointed Chief Executive Officer of AVANGRID effective July 22, 2020. Mr. Arriola joins the Avangrid, Inc. from Sempra Energy (Sempra), a publicly-traded energy infrastructure company, where he served as executive vice president and group president, and chief sustainability officer. Previously, he served as chairman, president and chief executive officer of Southern California Gas Co. (SoCalGas), one of Sempra's regulated California utilities. Mr. Arriola spent most of the past 26 years in a broad range of leadership roles for the Sempra companies including as chief executive officer of SoCalGas, senior vice president and chief financial officer of both San Diego Gas & Electric and SoCalGas, vice president of communications and investor relations for Sempra, and regional vice president and general manager of Sempra's South American operations. From 2008 to 2012, Mr. Arriola worked as executive vice president and president and chief financial officer for SunPower Corp., a Silicon Valley based solar technology company. Mr. Arriola previously served on the boards of directors for several Sempra operating companies, including Infraestructura Energética Nova (IEnova), a publicly-traded company in Mexico, Luz del Sur S.A.A., a publicly-traded company in Peru and Chilquinta Energía in Chile. He holds a bachelor's degree in economics from Stanford University and a master's degree in business administration from Harvard University. Mr. Arriola serves on the board of directors for Auto Club Enterprises, the U.S. Chamber of Commerce and the Edison Electric Institute, and previously served on the board of the California Business Roundtable and the California Latino Economic Institute.

Douglas K. Stuver. Mr. Stuver was appointed Senior Vice President - Chief Financial Officer of AVANGRID on July 8, 2018, and is responsible for AVANGRID's investor relations corporate communications, risk management, treasury and purchasing divisions. Mr. Stuver joined AVANGRID in 2015 as Managing Director, Finance of Avangrid Renewables, LLC and served as Vice President – Controller of Avangrid Renewables, LLC from 2017 until 2018. Prior to joining the Company, he served as chief financial officer of the Company's prior affiliate, PacifiCorp, from 2008 to 2015. Mr. Stuver graduated magna cum laude with a B.A. from University of Pittsburgh and is a Certified Public Accountant (inactive status).

Scott M. Tremble. Mr. Tremble was appointed Senior Vice President – Controller of AVANGRID on May 1, 2018, and is responsible for the execution and recording of AVANGRID's transactional processes while meeting mandatory reporting requirements and tax obligations. Mr. Tremble also serves as a director of AVANGRID's subsidiaries Networks, Renewables and UIL. Mr. Tremble joined the Company as chief accounting officer of Avangrid Management Company, LLC, a wholly-owned subsidiary of AVANGRID, in 2015, and was responsible for oversight in the areas of consolidation, financial reporting, internal controls, technical accounting and corporate accounting for the Company. From 2014 to 2015, he served as the international controller of Cole Haan LLC. Mr. Tremble started his career at PricewaterhouseCoopers in October 2002 and served various roles, including, most recently, as senior manager in the assurance practice. Mr. Tremble received his B.S. in Accountancy from Bentley University and is a Certified Public Accountant.

Alejandro de Hoz García-Bellido. Mr. de Hoz García-Bellido was appointed President and Chief Executive Officer of Renewables on October 15, 2019. Mr. de Hoz García-Bellido previously served as Vice President of U.S. Offshore Wind of Renewables from November 3, 2017 until October 15, 2019. Prior to joining Renewables, Mr. de Hoz García-Bellido served as Offshore Business Performance director within the Iberdrola offshore business from 2013 until 2017, based both in London and

Madrid, responsible for preparing Iberdrola's offshore pipeline for competitive auction processes both in the U.K. and Germany, as well as coordinating the teams to take awarded projects through the financial close. Prior to this, he held different positions within the Iberdrola group in developing the onshore wind business internationally, including the establishment in the French market and the development of the Mexican and Brazilian markets. Mr. de Hoz García-Bellido holds a degree in Physics from the University Complutense of Madrid and an MBA from ICAI-ICADE University of Madrid.

David T. Flanagan. Mr. Flanagan was appointed Executive Chairman of the Board of Directors of CMP effective February 18, 2020. Previously, Mr. Flanagan served as Chief Executive Officer of CMP from 1994 to 2000. Most recently, Mr. Flanagan served as the Interim President of the University of Southern Maine from 2014 until 2015. He also served as President and Chief Executive Officer at Preservation Management Inc., a management company specializing in affordable housing, from 2010 to 2013 and as General Counsel for the United States Senate Homeland Security Committee for the Hurricane Katrina investigation from 2005 until 2006. Prior to joining Central Maine Power Company, he served as legal counsel to the Governor of the State of Maine from 1979 to 1984 and as a member of the Board of Trustees of the University of Maine System from 1986 to 1995. Mr. Flanagan holds a Bachelor's Degree from Harvard University and a J.D. from Boston College Law School.

Peter T. Church. Mr. Church was appointed Senior Vice President – Human Resources & Corporate Administration of AVANGRID on October 31, 2018, and is responsible for ensuring that human resources strategies and initiatives support AVANGRID's mission and objectives, overseeing all aspects of human resources management, practices and operations, and coordinates AVANGRID's other corporate administrative functions including health and safety, general services, and information technology and systems. Prior to joining AVANGRID, Mr. Church held a number of executive positions at UnitedHealth Group from 2012 to 2018 including serving as the Chief Talent Officer, Vice President, Human Capital - Commercial Markets, and Vice President, Talent Acquisition and Workforce Insights. Mr. Church earned both a Bachelor of Arts in Psychology as well as a Master of Arts in General/Experimental Psychology from the University of Hartford.

Ignacio Estella. Mr. Estella was appointed Senior Vice President – Corporate Development of AVANGRID on December 17, 2015, and is responsible for delivering non-organic growth opportunities for the Company beyond those of its present businesses. Previously, Mr. Estella served as corporate vice president of business origination of Iberdrola from May 2009 until November 2013 and vice president – corporate development of Iberdrola USA, Inc., from December 2013 to December 16, 2015. He served as gas markets development director of Iberdrola between February 2007 and April 2009. Mr. Estella holds a degree in law and business administration from the Universidad Pontificia Comillas and a Master of Public Administration, with concentration in industry analysis and strategic negotiation, from Harvard University.

Robert D. Kump. Mr. Kump was appointed Deputy Chief Executive Officer and President of AVANGRID on June 5, 2019. Mr. Kump served as President and Chief Executive Officer of Networks from November 2010 until June 5, 2019 and as AVANGRID's Chief Corporate Officer from January 2014 to December 2016. Mr. Kump also served as a director of AVANGRID's subsidiaries CMP, NYSEG and RG&E from 2009 until June 5, 2019, and as the Chief Executive Officer of Avangrid Service Company from October 2009 until June 5, 2019. Mr. Kump held various positions from February 1997 to October 2009 as AVANGRID's senior vice president and chief financial officer, vice president, controller and chief accounting officer, treasurer and secretary. Mr. Kump also previously held a number of positions at NYSEG from 1986 to 1997, including senior accountant-external financial reporting, director-investor relations, director-financial services and treasurer. Mr. Kump earned a B.A. in accounting from Binghamton University and is a Certified Public Accountant in New York.

Carl A. Taylor. Mr. Taylor was appointed President and Chief Executive Office of NYSEG and RG&E on June 30, 2017. Previously, Mr. Taylor served as Vice President of Customer Service of AVANGRID. Mr. Taylor started with NYSEG in 1987 as an electrical engineer in the generation planning area and progressed through positions of increasing seniority in the organization including president of NYSEG Solutions, Inc., a subsidiary of NYSEG. He earned a Bachelor of Electrical Engineering Degree from Rochester Institute of Technology and a Master's of Business Administration Degree from State University of New York at Binghamton.

R. Scott Mahoney. Mr. Mahoney was appointed Senior Vice President – General Counsel of AVANGRID on December 17, 2015. He was appointed Secretary of AVANGRID on January 27, 2016, and previously served as vice president-general counsel and secretary of Networks. Mr. Mahoney previously served as Deputy General Counsel and Chief FERC Compliance Officer for AVANGRID from January 2007 to June 2012, and served in legal and senior executive positions at AVANGRID subsidiaries from October 1996 until January 2007. Mr. Mahoney also serves on the board of directors of the Gulf of Maine Research Institute. Mr. Mahoney earned a B.A. from St. Lawrence University, a J.D. from the University of Maine, a master's degree in environmental law from the Vermont Law School, and a postgraduate diploma in business administration from the University of Warwick. He has received bar admission to the State of Maine, the State of New York, the U.S. Court of Appeals, the U.S. District Court and the U.S. Court of Military Appeals and is a State of Connecticut Authorized House Counsel.

Anthony Marone. Mr. Marone was appointed President and Chief Executive Officer of Networks on June 5, 2019. In this role, he has overall responsibility for Avangrid Networks' electric and natural gas operating companies in Connecticut and Massachusetts and functional responsibility for AVANGRID's regulatory and asset management and planning. Mr. Marone also serves as President – Connecticut and Massachusetts Operations of Networks, director of Avangrid Enterprises, Inc., Avangrid Networks, Inc., Avangrid Networks New York TransCo, LLC, Avangrid Service Company, Berkshire Energy Resources, The Berkshire Gas Company, Central Maine Power Company, CMP Group, Inc., Connecticut Energy Corporation, Connecticut Natural Gas Corporation, CTG Resources, Inc., Mainecom Services, New York State Electric & Gas Corporation, RGS Energy Group, Inc., Rochester Gas and Electric Corporation, The Southern Connecticut Gas Company, Thermal Energies, Inc., UIL Group, LLC, UIL Holdings Corporation, The Union Water-Power Company, United Capital Investment, Inc., The United Illuminating Company, United Resources, Inc., Xcelecom, Inc., and Xcel Services, Inc. Previously Mr. Marone served as senior vice president of customer and business services of UIL since May 14, 2013. Mr. Marone served as senior vice president – business services of UI and vice president of business services of UIL from November 16, 2010 to May 2013. Mr. Marone received his master's degree in engineering and business management from the University of New Haven and a bachelor's degree in mechanical engineering from the New York Institute of Technology.

Franklyn Reynolds. Mr. Reynolds was appointed president and chief executive officer of UIL Holdings Corporation on October 20, 2020. From January 2019 to October 19, 2020, Mr. Reynolds served as the president of The Berkshire Gas Company. He also served as Vice President of Gas Integration from October 2017 to October 2020 and Vice President Asset Management and Planning of Avangrid Service Company from May 2013 to October 2017 where he was responsible for Electric Transmission & Distribution Planning, Vegetation Management, Substation Maintenance and Investment Planning. Mr. Reynolds earned a master's degree in business administration from the University of New Haven and a bachelor's degree in industrial technology from Central Connecticut State University. He is certified as a supply chain professional and has completed executive courses at Iberdrola's School of Management, Ross School of Business and Wharton School of Business.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Market Information and Holders

Our shares of common stock began trading on the NYSE on December 17, 2015, under the symbol "AGR." Prior to that time, there was no public market for shares of our common stock.

As of February 26, 2021, there were 3,286 shareholders of record.

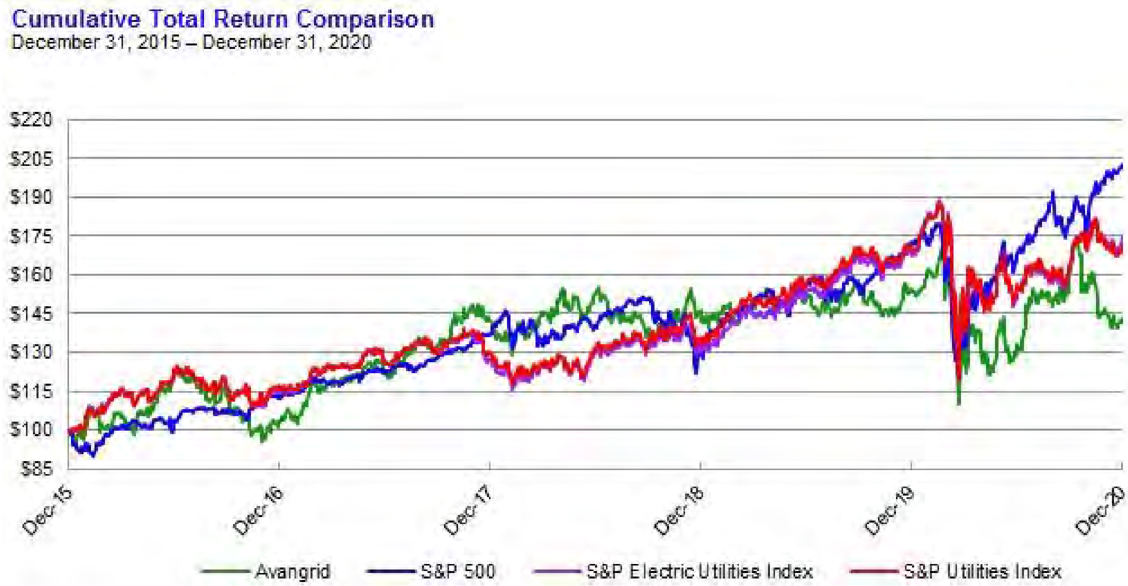
Dividends

AVANGRID expects to continue paying quarterly cash dividends, although there is no assurance as to the amount of future dividends, which depends on future earnings, capital requirements and financial condition.

Further information regarding payment of dividends is provided in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of this Annual Report on Form 10-K.

Performance Graph

The line graph appearing below compares the change in AVANGRID's total shareowner return on its shares of common stock with the return on the S&P Composite-500 Stock Index, the S&P Electric Utilities Index and the S&P Utilities Index for the period December 31, 2015 through December 31, 2020.



	December 31, 2015		December 31, 2020	
AVANGRID	$	100.00	$	142.64
S&P 500	$	100.00	$	202.96
S&P Electric Utilities Index	$	100.00	$	174.91
S&P Utilities Index	$	100.00	$	172.38

The above information assumes that the value of the investment in shares of AVANGRID's common stock and each index was $100 on December 31, 2015, including dividend reinvestment during this time period. The changes displayed are not necessarily indicative of future returns.

Recent Sales of Unregistered Securities

None.

Issuer Repurchases of Equity Securities

There were no repurchases of common stock of AVANGRID during the fourth quarter of the year ended December 31, 2020.

Equity Compensation Plan Information

For information regarding securities authorized for issuance under equity compensation plans, see Part III, Item 12 of this Annual Report on Form 10-K.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

You should read the following discussion of our financial condition and results of operations in conjunction with the consolidated financial statements and the notes thereto included elsewhere in this Annual Report on Form 10-K. In addition to historical consolidated financial information, the following discussion contains forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to these differences include those discussed below and elsewhere in this Annual Report on Form 10-K, particularly in Part I, Item 1A, "Risk Factors."

Overview

AVANGRID is one of the leading sustainable energy companies in the United States. Our purpose is to work every day to deliver a more accessible clean energy model that promotes healthier, more sustainable communities. A commitment to sustainability is firmly entrenched in the values and principles that guide AVANGRID, with environmental, social, governance and financial sustainability key priorities driving our business strategy.

AVANGRID has approximately $38 billion in assets and operations in 24 states concentrated in our two primary lines of business - Avangrid Networks and Avangrid Renewables. Avangrid Networks owns eight electric and natural gas utilities, serving approximately 3.3 million customers in New York and New England. Avangrid Renewables owns and operates 8.5 gigawatts of electricity capacity through primarily wind and solar power, with a presence in 22 states across the United States. AVANGRID supports the achievement of the Sustainable Development Goals approved by the member states of the United Nations, and was named among the World's Most Ethical companies in 2019 and 2020 by the Ethisphere Institute and is listed by Forbes and Just Capital as one of the 2021 Just 100, an annual ranking of the most just U.S. public companies. AVANGRID employs approximately 7,000 people. Iberdrola S.A., a corporation *(sociedad anónima)* organized under the laws of the Kingdom of Spain, a worldwide leader in the energy industry, directly owns 81.5% of the outstanding shares of AVANGRID common stock. AVANGRID's primary businesses are described below.

Our direct, wholly-owned subsidiaries include Avangrid Networks, Inc., or Networks, and Avangrid Renewables Holdings, Inc., or ARHI. ARHI in turn holds subsidiaries including Avangrid Renewables, LLC, or Renewables. Networks owns and operates our regulated utility businesses through its subsidiaries, including electric transmission and distribution and natural gas distribution, transportation and sales. Renewables operates a portfolio of renewable energy generation facilities primarily using onshore wind power and also solar, biomass and thermal power.

Through Networks, we own electric generation, transmission and distribution companies and natural gas distribution, transportation and sales companies in New York, Maine, Connecticut and Massachusetts, delivering electricity to approximately 2.3 million electric utility customers and delivering natural gas to approximately 1.0 million natural gas utility customers as of December 31, 2020.

Networks, a Maine corporation, holds our regulated utility businesses, including electric transmission and distribution and natural gas distribution, transportation and sales. Networks serves as a super-regional energy services and delivery company through the eight regulated utilities it owns directly:

- New York State Electric & Gas Corporation, or NYSEG, which serves electric and natural gas customers across more than 40% of the upstate New York geographic area;
- Rochester Gas and Electric Corporation, or RG&E, which serves electric and natural gas customers within a nine-county region in western New York, centered around Rochester;
- The United Illuminating Company, or UI, which serves electric customers in southwestern Connecticut;
- Central Maine Power Company, or CMP, which serves electric customers in central and southern Maine;
- The Southern Connecticut Gas Company, or SCG, which serves natural gas customers in Connecticut;
- Connecticut Natural Gas Corporation, or CNG, which serves natural gas customers in Connecticut;
- The Berkshire Gas Company, or BGC, which serves natural gas customers in western Massachusetts; and
- Maine Natural Gas Corporation, or MNG, which serves natural gas customers in several communities in central and southern Maine.

Through Renewables, we had a combined wind, solar and thermal installed capacity of 8,499 megawatts, or MW, as of December 31, 2020, including Renewables' share of joint projects, of which 7,734 MW was installed wind capacity. As of December 31, 2020, approximately 67% of the capacity was contracted, for an average period of 9.0 years, and 18% of installed capacity was hedged. Being among the top three largest wind operators in the United States based on installed capacity as of December 31, 2020, Renewables strives to lead the transformation of the U.S. energy industry to a sustainable, competitive, clean energy future. Renewables installed capacity includes 65 wind farms and four solar facilities in 21 states across the United States.

February 2021 Texas Weather Event

During February 2021, Texas experienced unprecedented extreme cold weather, resulting in outages impacting millions in the state. Despite this challenge, our team worked safely to operate our Texas wind generation facilities to their maximum potential given the difficult conditions. Through our risk management procedures, we met all of our delivery obligations in Texas and produced excess energy, contributing to the solution for our customers during this critical period. If the expected amounts are not approved for recovery by ERCOT, it could adversely affect our results.

Proposed Merger with PNMR

On October 20, 2020, AVANGRID, PNM Resources, Inc., a New Mexico corporation, or PNMR, and NM Green Holdings, Inc., a New Mexico corporation and wholly-owned subsidiary of AVANGRID, or Merger Sub, entered into an Agreement and Plan of Merger, or Merger Agreement, pursuant to which Merger Sub is expected to merge with and into PNMR, with PNMR surviving the Merger as a direct wholly-owned subsidiary of AVANGRID, or the Merger. PNMR is a publicly-owned holding company with two regulated utilities providing electricity and electric services in New Mexico and Texas. PNMR's electric utilities are the Public Service Company of New Mexico and the Texas-New Mexico Power Company. Following consummation of the Merger, AVANGRID will expand its geographic and regulatory diversity with ten regulated electric and gas companies in six states to help expand our growing leadership position in transforming the U.S. energy industry.

Pursuant to the Merger Agreement, each issued and outstanding share of the common stock of PNMR (other than (i) the issued shares of PNMR common stock that are owned by AVANGRID, Merger Sub, PNMR or any wholly-owned subsidiary of AVANGRID or PNMR, which will be automatically cancelled at the time the Merger is consummated and (ii) shares of PNMR common stock held by a holder who has not voted in favor of, or consented in writing to, the Merger who is entitled to, and who has demanded, payment for fair value of such shares) will be converted, at the time the merger is consummated, into the right to receive $50.30 in cash, or Merger Consideration, or approximately $4.3 billion in aggregate consideration. In connection with the Merger, Iberdrola, S.A. has provided the Iberdrola Funding Commitment Letter, pursuant to which Iberdrola has unilaterally agreed to provide to AVANGRID, or arrange the provision to AVANGRID of, funds to the extent necessary for AVANGRID to consummate the Merger, including the payment of the aggregate Merger Consideration. On February 12, 2021, the shareholders of PNMR approved the proposed Merger. The Merger is expected to close in the second half of 2021 and is subject to certain conditions including certain regulatory approvals and entry into agreements providing for, and to making filings required to, exit from all ownership interests in the Four Corners Power Plant and certain other customary closing conditions.

In connection with the Merger, purported shareholders of PNMR have filed lawsuits against PNMR and the members of the PNMR board of directors under the federal securities laws, challenging the adequacy of the disclosures made in PNMR's proxy statement in connection with the Merger or otherwise. We cannot predict the outcome of these lawsuits.

For additional information on the Merger, see Note 1 - Background and Nature of Operations.

COVID-19

The COVID-19 pandemic has led to global economic disruption and volatility in financial markets and the United States economy. AVANGRID is one of the many companies providing essential services during this national emergency and we communicate regularly with federal and state authorities and industry resources to ensure a coordinated response. We have implemented business continuity and emergency response plans to continue to provide service to our customers and support our operational needs. We continue to monitor developments affecting both our workforce and our customers and will take precautions that we determine are necessary or appropriate. We regularly communicate with our customers regarding the tools and resources available and to help our customers stay informed during this public health crisis. In addition to measures to protect our workforce and critical operations, we have established a cross-functional task force to plan for a safe and effective return to office. AVANGRID is actively monitoring potential supply chain and transportation disruptions that could impact the Company's operations and will implement plans to address any such impacts on our business.

This is a rapidly evolving situation that could continue to lead to extended disruption of economic activity in our markets, which could adversely affect our business. We have not yet experienced a materially adverse impact to our business, results of operations or financial condition, however, given the uncertain scope and duration of the COVID-19 outbreak and its potential effects on our business, we currently cannot predict if there will be materially adverse impacts to our business, results of operations or financial condition in the future.

For more information, see the risk factor under the heading "The outbreak of COVID-19 and its impact on business and economic conditions could negatively affect our business, results of operations or financial condition." in Item 1A. Risk Factors in this Form 10-K.

Summary of Results of Operations

Our operating revenues decreased by less than 1%, from $6,336 million for the year ended December 31, 2019, to $6,320 million for the year ended December 31, 2020.

Networks business revenues increased mainly due to increased customer rates in the period. Renewables had a decrease in revenues mainly due to unfavorable mark to market, or MtM, changes on energy derivative transactions entered into for economic hedging purposes.

Net income attributable to AVANGRID decreased by 13% from $667 million for the year ended December 31, 2019, to $581 million for the year ended December 31, 2020, primarily as a result of gain from the sale of assets in Renewables in 2019 that did not recur in 2020.

Adjusted net income (a non-GAAP financial measure) decreased by 2%, from $640 million for the year ended December 31, 2019 to $625 million for the year ended December 31, 2020. The decrease is primarily due to a $77 million decrease in Renewables as a result of gain from the sale of assets in 2019 that did not recur in 2020 and a $41 million decrease in Corporate mainly driven by higher interest expenses in the period, offset by a $103 million increase in Networks driven primarily by approved rate cases in the period.

For additional information and reconciliation of the non-GAAP adjusted net income to net income attributable to AVANGRID, see "*—Non-GAAP Financial Measures*."

See "*—Results of Operations*" for further analysis of our operating results for the year.

Our financial condition and financing capability will be dependent on many factors, including the level of income and cash flow of its subsidiaries, conditions in the bank and capital markets, economic conditions, interest rates and legislative and regulatory developments.

Networks

Electric Transmission and Distribution and Natural Gas Distribution

The operating subsidiaries of Networks are regulated electric distribution and transmission and natural gas transportation and distribution utilities whose structure and operations are significantly affected by legislation and regulation. The FERC regulates, under the FPA, the interstate transmission and wholesale sale of electricity by these regulated utilities, including transmission rates and allowed ROE on transmission assets. Further, the distribution rates and allowed ROEs for Networks' regulated utilities in New York, Maine, Connecticut and Massachusetts are subject to regulation by the NYPSC, the MPUC, PURA and DPU, respectively. Legislation and regulatory decisions implementing legislation establish a framework for Networks' operations. Other factors affecting Networks' financial results are operational matters, such as the ability to manage expenses, uncollectibles and capital expenditures, in addition to major weather disturbances and environmental regulation. Networks expects to continue to make significant capital investments in its distribution and transmission infrastructure.

Pursuant to Maine law, CMP earns revenue for the delivery of energy to its retail customers, but is prohibited from selling power to them. CMP generally does not enter into purchase or sales arrangements for power with ISO-NE, the New England power pool, or any other ISO or similar entity. CMP generally sells all of its power entitlements under its nonutility generator and other PPAs to unrelated third parties under bilateral contracts. If the MPUC does not approve the terms of bilateral contracts, it can direct CMP to sell power entitlements that it receives from those contracts on the spot market through ISO-NE. NYSEG and RG&E enter into power purchase and sales transactions with the NYISO to have adequate supplies for their customers who choose to purchase energy directly from them. Customers may also choose to purchase energy from other energy supply companies.

Under Connecticut law, UI's retail electricity customers are able to choose their electricity supplier while UI remains their electric distribution company. UI purchases power for those of its customers under standard service rates who do not choose a retail electric supplier and have a maximum demand of less than 500 kilowatts and its customers under supplier of last resort service for those who are not eligible for standard service and who do not choose to purchase electric generation service from a retail electric supplier. The cost of the power is a “pass-through” to those customers through the generation services charge on their bills.

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2021, 70% of its standard service load for the second half of 2021 and 20% of its standard service load for the first half of 2022. Supplier of last resort service is procured on a quarterly basis and UI has a wholesale power supply agreement in place for the second quarter of 2021. However, from time to time, there are no bidders in the procurement process for supplier of last resort service and UI manages the load directly.

For additional information regarding Networks, including a comprehensive overview of our regulated businesses, please see the section entitled, “Business—Networks” in Part I, Item 1 in this report.

Revenues

Networks utilizes regulatory deferrals to evaluate its financial condition and operating performance by reconciling differences between actual revenue received or cost incurred with the rate allowances provided under the tariffs set by the state utilities commissions and the FERC. Regulatory deferrals create regulatory assets and liabilities under the FERC, consistent with generally accepted accounting principles for financial reporting in the United States, or U.S. GAAP.

Regulatory deferrals in New York include electric and gas supply costs, PPAs, net plant reconciliations (downward only), revenue decoupling, system benefit charges, RPS, energy efficiency portfolio standards, including heat pumps, economic development programs, earnings sharing mechanism, electric vehicle program costs, labor FTE's, low income programs, pension costs, other post-employment benefits costs, environmental remediation costs, major storm costs, distribution vegetation management costs (downward only), gas research and development, incremental maintenance initiatives (downward only), management audit consultant and implementation costs, property taxes, Reforming the Energy Vision, or REV, initiatives, Nuclear Electric Insurance Limited credits, credit and debit card fees, debt costs, power tax, 2017 Tax Act, exogenous costs and certain legislative, accounting, regulatory and tax related actions.

Regulatory deferrals in Maine include stranded costs, distribution revenue decoupling, power tax regulatory asset, 2017 Tax Act, environmental remediation, storm reserve accounting, electric thermal storage pilot costs, standard offer retainage costs, AMI opt-out program costs, AMI deferral costs, AMI legal/health proceeding costs, conservation program costs, demand side management costs, low income program costs, electric lifeline program costs, make-ready line extension costs, electric vehicle pilot program costs and transmission planning and related cost allocation.

Regulatory deferrals in Connecticut include electric and gas supply costs, PPAs, revenue decoupling, earnings sharing mechanism, system benefit charges, certain hardship bad debt expense, transmission revenue requirements, gas distribution integrity management program costs, gas system expansion costs, certain public policy costs, certain environmental remediation costs, major storm costs and certain legislative, accounting, regulatory and tax related actions.

Regulatory deferrals in Massachusetts include gas supply costs, gas supply-related bad debt costs, environmental remediation costs, arrearage management program costs, gas system enhancement program costs, energy efficiency program costs, 2017 Tax Act and certain other public policy costs.

Each of Networks' regulated utilities' rate plans, other than MNG, contain an RDM under which their actual energy delivery revenues are compared on a periodic basis with the authorized delivery revenues and the difference accrued, with interest, for refund to or recovery from customers, as applicable.

NYSEG, RG&E and UI are energy delivery companies and also provide energy supply as providers of last resort. Energy costs that are set on the wholesale markets are passed on to consumers. The difference between actual energy costs that are incurred and those that are initially billed are reconciled in a process that results in either immediate or deferred tariff adjustments. These procedures apply to other costs, which are in most cases exceptional, such as the effects of extreme weather conditions, environmental factors, regulatory and accounting changes and treatment of vulnerable customers, that are offset in the tariff process.

Pursuant to agreements with, or decisions of the NYPSC and the MPUC, Networks’ Maine and New York regulated utilities are each subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements, each of NYSEG, RG&E, CMP and MNG must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, each utility must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that can be paid if the minimum equity ratio is not maintained and can, under certain circumstances, require that AVANGRID contribute equity capital. For CMP and MNG, equity distributions that would result in equity falling below the minimum level are prohibited. For

NYSEG and RG&E, equity distributions that would result in a 13-month average common equity less than the maximum equity ratio utilized for the earnings sharing mechanism, or ESM, are prohibited if the credit rating of NYSEG, RG&E, AVANGRID or Iberdrola are downgraded by a nationally recognized rating agency to the lowest investment grade with a negative watch or downgraded to noninvestment grade. UI, SCG, CNG and BGC may not pay dividends if paying such dividend would result in a common equity ratio lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. In addition, UI, SCG, CNG and BGC are prohibited from paying dividends to their parent if the utility's credit rating, as rated by any of the three major credit rating agencies, falls below investment grade, or if the utility's credit rating, as determined by two of the three major credit rating agencies, falls to the lowest investment grade and there is a negative watch or review downgrade notice. We believe that these minimum equity ratio requirements do not present any material risk with respect to our performance, cash flow or ability to pay quarterly dividends. In the ordinary course, Networks utilities manage their capital structures to allow the maximum level of returns consistent with the levels of equity authorized to set rates, and accordingly, compliance with these requirements does not alter ordinary equity level management. The regulated utility subsidiaries are also prohibited by regulation from lending to unregulated affiliates.

Rates

In December 2016, PURA approved new distribution rate schedules for UI for three years, which became effective January 1, 2017 and, among other things, provide for annual tariff increases and an ROE of 9.10% based on a 50.00% equity ratio, continued UI's existing ESM pursuant to which UI and its customers share on a 50/50 basis all distribution earnings above the allowed ROE in a calendar year, continued the existing decoupling mechanism and approved the continuation of the requested storm reserve. Any dollars due to customers from the ESM continue to be first applied against any storm regulatory asset balance (if one exists at that time) or refunded to customers through a bill credit if such storm regulatory asset balance does not exist.

In December 2017, PURA approved new tariffs for SCG effective January 1, 2018, for a three-year rate plan with annual rate increases. The new tariffs also include an RDM and Distribution Integrity Management Program (DIMP) mechanism, ESM, the amortization of certain regulatory liabilities (most notably accumulated hardship deferral balances and certain accumulated deferred income taxes) and tariff increases based on a ROE of 9.25% and approximately 52.00% equity level. Any dollars due to customers from the ESM will be first applied against any environmental regulatory asset balance as defined in the settlement agreement (if one exists at that time) or refunded to customers through a bill credit if such environmental regulatory asset balance does not exist.

In December 2018, PURA approved new tariffs for CNG effective January 1, 2019 for a three-year rate plan with annual rate increases. The new tariffs continued the RDM and DIMP mechanism, ESM and tariff increases based on an ROE of 9.30% and an equity ratio of 54.00% in 2019, 54.50% in 2020 and 55.00% in 2021.

On January 18, 2019, the DPU approved new distribution rates for BGC. The distribution rate increase is based on an ROE of 9.70% and 54.00% equity ratio. The new tariffs provide for the implementation of an RDM and pension expense tracker and also provide that BGC will not file to change base distribution rates to become effective before November 1, 2021.

On June 15, 2016, the NYPSC approved NYSEG's and RG&E's 2016 Joint Proposal for a three-year rate plan for electric and gas service which balanced the varied interests of the signatory parties including but not limited to maintaining the companies' credit quality and mitigating the rate impacts to customers. The 2016 Joint Proposal reflected many customer benefits including: acceleration of the companies' natural gas leak prone main replacement programs and increased funding for electric vegetation management to provide continued safe and reliable service. The delivery rate increases for the last year of the 2016 Joint Proposal can be summarized as follows:

	May 1, 2018	
Utility	**Rate Increase (Millions)**	**Delivery Rate Increase %**
NYSEG Electric	$ 30	4.10 %
NYSEG Gas	$ 15	7.30 %
RG&E Electric	$ 26	5.70 %
RG&E Gas	$ 10	5.20 %

The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas was 9.00%. The equity ratio for each company was 48.00%; however, the equity ratio was set at the actual up to 50.00% for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increased as the ROE increased, with customers receiving 50.00%, 75.00% and 90.00% of earnings in rate year three (May 1, 2018 – April 30, 2019) above 9.75%, 10.25% and 10.75% ROE, respectively. The rate plans also included the implementation of a rate adjustment mechanism (RAM) designed to return or collect certain defined reconciled revenues and costs, new depreciation rates and continuation of the existing RDM for each business. The 2016 Joint Proposal reflected the recovery of deferred NYSEG Electric storm costs of approximately $262 million, of which $123 million is being amortized over ten years and the remaining $139 million is being amortized over five years. The proposal also continues reserve accounting for qualifying Major Storms ($21 million annually for NYSEG Electric and $3 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds.

On June 22, 2020, NYSEG and RG&E filed a joint proposal with the NYPSC for a new three-year rate plan, or the 2020 Joint Proposal. On November 19, 2020, the NYPSC approved the 2020 Joint Proposal, with modifications to the rate increases at the two electric businesses. The modifications were made to limit the overall bill impacts, to a level at or below 2.00% per year, in consideration of the current impacts of COVID-19 on the economic climate. The effective date of new tariffs was December 1, 2020 with a make-whole provision back to April 17, 2020. The proposed rates facilitate the companies' transition to a cleaner energy future while allowing for important initiatives such as COVID-19 relief for customers and additional funding for vegetation management, hardening/resiliency and emergency preparedness. The rate plans continue the RAM designed to return or collect certain defined reconciled revenues and costs, have new depreciation rates and continue existing RDMs for each business. The 2020 Joint Proposal bases delivery revenues on an 8.80% ROE and 48.00% equity ratio; however, for the proposed earnings sharing mechanism, the equity ratio is the lower of the actual equity ratio or 50.00%. The below table provides a summary of the approved delivery rate increases and delivery rate percentages, including rate levelization and excluding energy efficiency, which is a pass-through, for all four businesses:

	Year 1		Year 2		Year 3	
Utility	**Rate Increase (Millions)**	**Delivery Rate Increase %**	**Rate Increase (Millions)**	**Delivery Rate Increase %**	**Rate Increase (Millions)**	**Delivery Rate Increase %**
NYSEG Electric	$ 34	4.6 %	$ 46	5.9 %	$ 36	4.2 %
NYSEG Gas	$ —	— %	$ 2	0.8 %	$ 3	1.6 %
RG&E Electric	$ 17	3.8 %	$ 14	3.2 %	$ 16	3.3 %
RG&E Gas	$ —	— %	$ —	— %	$ 2	1.3 %

In an order issued on February 19, 2020, the MPUC authorized an increase in CMP's distribution revenue requirement of $17 million, or approximately 7.00%, based on an allowed ROE of 9.25% and a 50.00% equity ratio. The rate increase was effective March 1, 2020. The MPUC also imposed a 1.00% ROE reduction (to 8.25%) for management efficiency associated with CMP's customer service performance following the implementation of its new billing system in 2017. The management efficiency adjustment will remain in effect until CMP has demonstrated satisfactory customer service performance on four specified service quality measures for a rolling average period of 18 months, which commenced on March 1, 2020. CMP is meeting the required rolling average benchmarks on all four of these quality measures.

The order provided additional funding for staffing increases, vegetation management programs and storm restoration costs, while retaining the basic tiered structure for storm cost recovery implemented in the 2014 stipulation. The MPUC order also retained the RDM implemented in 2014. The order denied CMP's request to increase rates for higher costs associated with services provided by its affiliates and ordered the initiation of a management audit to evaluate whether CMP's current management structure, and the management and other services from its affiliates, are appropriate and in the interest of Maine customers. The management audit was commenced in July 2020 by the MPUC's consultants and is expected to conclude in 2021.

On May 17, 2016, the MPUC approved MNG's ten-year rate plan through April 30, 2026. The settlement structure for non-Augusta customers includes a 34.60% delivery revenue increase over five years with an allowed 9.55% ROE and 50.00% common equity ratio. The settlement structure for Augusta customers includes a ten-year rate plan with existing Augusta customers being charged rates equal to non-Augusta customers plus a surcharge which increases annually for five years. New Augusta customers will have rates set based on an alternate fuel market model. In year seven of the rate plan MNG will submit a cost of service filing for the Augusta area to determine if the rate plan should continue. This cost of service filing will exclude $15 million of initial 2012/2013 gross plant investment, however the stipulation allows for accelerated depreciation of these assets. If the Augusta area's cost of service filing illustrates results above a 14.55% ROE then the rate plan may cease, otherwise the rate plan would continue.

CMP's and UI's electric transmission rates are determined by a tariff regulated by the FERC and administered by ISO-NE. Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, including return of and on investment in assets. The FERC currently provides an initial base ROE of 10.57% and additional incentive adders applicable to assets based upon vintage, voltage and other factors.

In September 2011, several New England governmental entities, including PURA, the Connecticut Attorney General and the Connecticut Office of Consumer Counsel filed a joint complaint with the FERC against ISO-NE and several New England Transmission Owners, or NETOs, (including CMP and UI) claiming that the current approved base ROE used in calculating formula rates for transmission service under the ISO-NE Open Access Transmission Tariff, or OATT, by the NETOs of 11.14% was not just and reasonable and seeking a reduction of the base ROE with refunds to customers for the 15-month refund periods beginning October 1, 2011 (Complaint I), December 27, 2012 (Complaint II), July 31, 2014 (Complaint III) and April 29, 2016 (Complaint IV).

Following various intermediate hearings, orders, and appellate decisions, on October 16, 2018, the FERC issued an order directing briefs and proposing a new methodology to calculate the NETOs ROE that is contained in NETOs' transmission formula rate on file at the FERC, or the October 2018 Order. The FERC proposed to use this new methodology to resolve Complaints I, II, III and IV filed by the New England state consumer advocates.

The proposed ROE methodology set forth in the October 2018 Order considers more than just the two-step discounted cash flow, or DCF, analysis adopted in the FERC order on Complaint I vacated by the Court. It uses four financial analyses (i.e., DCF, the capital-asset pricing model, expected earnings analysis and risk premium analysis) to produce a range of returns to narrow the zone of reasonableness when assessing whether a complainant has met its initial burden of demonstrating that the utility's existing ROE is unjust and unreasonable. The proposed ROE methodology establishes a range of just and reasonable ROEs of 9.60% to 10.99% and proposes a just and reasonable base ROE of 10.41% with a new ROE cap of 13.08%. Pursuant to the October 2018 Order, the NETOs filed initial briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019. On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing of this decision. We cannot predict the outcome of this proceeding, and the potential impact it may have in establishing a precedent for our pending four Complaints.

Legislative and Regulatory Update

New England Clean Energy Connect

In 2018, the New England Clean Energy Connect, or NECEC, transmission project, proposed in a joint bid by CMP and Hydro-Québec, was selected by the Massachusetts electric distribution utilities (EDCs) and the Massachusetts Department of Energy Resources, or DOER, in the Commonwealth of Massachusetts's 83D clean energy Request for Proposal. The NECEC transmission project includes a 145-mile transmission line linking the electrical grids in Québec, Canada and New England. The project, which has an estimated cost of approximately $1.0 billion, will add 1,200 MW of transmission capacity to supply Maine and the rest of New England with power from reliable hydroelectric generation. As of December 31, 2020, we have spent approximately $180 million on the NECEC project.

On June 13, 2018, CMP entered into transmission service agreements, or TSAs, with the Massachusetts EDCs, and H.Q. Energy Services (U.S.) Inc., or HQUS, an affiliate of Hydro-Québec, which govern the terms of service and revenue recovery for the NECEC transmission project. Simultaneous with the execution of the TSAs with CMP, the EDCs executed certain PPAs with HQUS for sales of electricity and environmental attributes to the EDCs. On October 19, 2018, FERC issued an order accepting the TSAs for filing as CMP rate schedules effective as of October 20, 2018. On June 25, 2019, the Massachusetts DPU issued an Order approving the NECEC project long term PPAs and the cost recovery by the EDCs of the TSA charges. This Order was subsequently appealed by NextEra Energy Resources. On September 3, 2020, the Massachusetts Supreme Judicial Court denied NextEra Energy Resources' appeal of the DPU Order.

The NECEC project requires a Certificate of Public Convenience and Necessity, or CPCN, from the MPUC. On May 3, 2019, the MPUC issued an Order granting the CPCN for the NECEC project and approving a stipulation dated February 21, 2019, or the NECEC I Stipulation. Among other things, the NECEC I Stipulation provided for the transfer of the NECEC transmission project from CMP to NECEC Transmission LLC, a new subsidiary of Networks; the funding by NECEC Transmission LLC, CMP and HQUS of certain funds to provide benefits to the State of Maine totaling approximately $250 million during construction and over the 40-year useful life of the NECEC transmission project; and other commitments. The NECEC I Stipulation also required CMP, NECEC Transmission LLC and HQUS to enter into a support agreement reflecting, among other things, HQUS's commitment to fund certain of the funds to provide benefits to the State of Maine, or the Support Agreement.

In compliance with the conditions set forth in the MPUC May 3, 2019 Order, in August 2019, CMP and NECEC Transmission LLC filed a joint petition in a new proceeding before the MPUC to, among other, obtain approval of the various affiliate transactions involved in the transfer of the NECEC project from CMP to NECEC Transmission LLC. On October 20, 2020, the MPUC issued an Order approving a stipulation dated July 30, 2020, entered into by CMP, NECEC Transmission LLC, and certain other parties to resolve all issues among them in connection with this proceeding, or the NECEC II Stipulation. In addition to addressing the transfer of the NECEC project from CMP to NECEC Transmission LLC, the NECEC II Stipulation contains further details regarding implementation of some of the commitments set forth in the NECEC I Stipulation.

On December 10, 2019, CMP submitted a petition to the FERC, seeking FERC's authorization to transfer the TSAs (FERC rate schedules) from CMP to NECEC Transmission LLC upon the project's transfer. On March 13, 2020, FERC authorized the transfer of the rate schedules.

On June 25, 2020, the parties to the TSAs executed the Second Amendment to the TSAs and Consent to Assignment, whereby the EDCs and HQUS consented to CMP's assignment of the TSAs to NECEC Transmission LLC. On October 2, 2020, NECEC Transmission LLC submitted notices of succession to the FERC to notify the FERC of the transfer of the seven TSAs from CMP to NECEC Transmission LLC effective as of the closing of the transfer. On October 2, 2020, CMP submitted a notice of cancellation notifying FERC of the prospective cancellation of the TSAs as CMP rate schedules. On November 30, 2020 and December 18, 2020, FERC accepted the notices of succession. On December 18, 2020, FERC also accepted CMP's notice of cancellation.

On December 29, 2020, CMP, NECEC Transmission LLC and HQUS executed the Support Agreement. In addition, Avangrid, Inc. issued the parent guarantees required pursuant to the NECEC I Stipulation and further described by the NECEC II Stipulation.

On January 4, 2021, CMP transferred the NECEC project to NECEC Transmission LLC pursuant to the terms of a transfer agreement dated November 3, 2020. Among other things, on that date, CMP assigned the TSAs to NECEC Transmission LLC.

The NECEC project requires certain permits, including environmental, from multiple state and federal agencies and a presidential permit from the U.S. Department of Energy authorizing the construction, operation, maintenance and connection of facilities for the transmission of electric energy at the international border between the United States and Canada. On January 8, 2020, the Maine Land Use Planning Commission, or LUPC, deliberated and granted the LUPC Certification for the NECEC. The Maine Department of Environmental Protection, or MDEP, granted Site Location of Development Act, Natural Resources Protection Act, and Water Quality Certification permits for the NECEC by an Order dated May 11, 2020. The MDEP Order has been appealed by certain intervenors. The appeals are currently pending before the Maine Board of Environmental Protection. Certain parties to the MDEP proceedings requested the stay of the MDEP permits during the pendency of the appeals. The motions to stay were denied by the MDEP Commissioner in August 2020. On November 2, 2020, a motion to stay the MDEP permits was filed before the Maine Superior Court by certain parties. In January 2021, the Maine Superior Court denied the motion for a stay. We cannot predict the outcome of these proceedings.

On November 6, 2020, the project received the required approvals from the Army Corps pursuant to Section 10 of the Rivers and Harbor Act of 1899 and Section 404 of the Clean Water Act. A complaint for declaratory and injunctive relief asking the court to vacate or remand the Section 404 Clean Water Act permit for the NECEC project filed by three environmental groups is currently pending before the District Court in Maine. A related request for preliminary injunction seeking to enjoin construction of the NECEC was denied by the District Court on December 16, 2020. That denial was appealed to the First Circuit Court of Appeals. On December 21, 2020, plaintiffs filed a motion for emergency injunction pending appeal in the District Court. The District Court denied that motion on December 23, 2020. On December 30, 2020, plaintiffs filed an emergency motion for injunction with the First Circuit Court seeking to enjoin construction in Segment 1 of the project pending their appeal of the District Court's denial of a preliminary injunction. On January 15, 2021, the First Circuit Court granted the motion temporarily enjoining construction in Segment 1 of the NECEC project. We cannot predict the outcome of these proceedings.

ISO-NE issued the final System Impact Study (SIS) for NECEC on May 13, 2020, determining the network upgrades required to permit the interconnection of NECEC to the ISO-NE system. On July 9, 2020, the project received the formal I.3.9 approval associated with this interconnection request. CMP, NECEC Transmission LLC and ISO-NE executed an interconnection agreement. With respect to the system upgrade required at the Seabrook Station, on October 13, 2020, Avangrid and NECEC Transmission LLC filed a Complaint with the FERC. On October 5, 2020, NextEra Energy Seabrook, LLC filed a Petition for Declaratory Order. Both proceedings are currently pending before FERC.

On January 14, 2021, the Department of Energy issued a Presidential Permit granting permission to NECEC Transmission LLC to construct, operate, maintain and connect electric transmission facilities at the international border of the United States and Canada.

A complaint challenging the validity of NECEC Transmission LLC's leasehold interest in public land that will host a section of the NECEC project, granted by Maine's Bureau of Parks and Lands, is currently pending before the Maine Superior Court. We cannot predict the outcome of this proceeding.

In 2019, certain opponents of the NECEC began an effort to have a referendum ballot question to enact legislation (i.e., a Maine citizen initiative) entitled “Resolve, To Reject the New England Clean Energy Transmission Project,” which, if passed by Maine voters, would have required the MPUC to amend its May 3, 2019 Order granting a CPCN for the project and deny the CPCN. On August 13, 2020, the Maine Supreme Judicial Court vacated a June 29, 2020 Maine Superior Court decision, held that the referendum is unconstitutional and remanded the case to the Maine Superior Court to enter a declaratory judgment. On August 21, 2020, the Maine Superior Court issued a declaratory judgment that the referendum fails to meet the constitutional requirements for inclusion on the ballot.

On September 16, 2020, a group of Maine voters submitted an application for a citizen referendum (i.e., a Maine citizen initiative) to enact legislation that, if enacted into law and found to be constitutional, would require the vote of 2/3 of all members elected to each House of the Maine Legislature to approve construction of a high-impact electric transmission line crossing or utilizing public lands, prohibit construction of a high impact electric transmission line in the Upper Kennebec Region and require the vote of 2/3 of all members elected to each House of the Maine Legislature for the lease by Maine's Bureau of Parks and Lands of public reserved lands for transmission lines and similar linear projects. On February 22, 2021, the Maine Secretary of State issued a decision finding that proponents of the initiative have gathered the constitutionally required number of signatures and that the referendum is valid for placement on the November 2021 ballot. We cannot predict the outcome of this citizen initiative.

At the municipal level, the project plans to apply for and obtain local approvals from organized towns gradually, based on the project’s construction sequence and schedule. Seven towns have granted municipal approvals to date. Construction of the NECEC project started in January 2021 and commercial operation is expected in the second quarter of 2023.

Maine Government-Run Power Referendum

On September 18, 2020, a request was submitted to the Maine Secretary of State to initiate the process of placing a government-run power referendum on the ballot. We cannot predict the outcome of this request or any potential referendum.

CMP System Upgrades Due to Distributed Generation Demand

CMP has entered into certain interconnection agreements with distributed generation operators and/or developers. Due to the increased demand for solar distribution-side connections, certain reconfigurations of the grid and substation and systems upgrades may be necessary to prevent potential safety issues. CMP is analyzing the anticipated costs of the necessary upgrades and the distributed generation operations and/or developers responsibility for such costs under the interconnection agreements. We cannot predict the outcome of this matter, including any potential proceedings before the MPUC.

New England Clean Energy Request for Proposals

On May 25, 2017, UI entered into six 20-year PPAs, totaling approximately 32 MW with developers of wind and solar generation. These PPAs originated from a three-state Clean Energy RFP, and were entered into pursuant to PA 13-303, which provides that the net costs of the PPAs are recoverable through electric rates. The PPAs were approved by PURA on September 13, 2017.

On June 20, 2017, UI entered into twenty-two 20-year PPAs totaling approximately 72 MW with developers of wind and solar generation. These PPAs originated from an RFP issued by the DEEP under PA 15-107 1(b) which provides that the net costs of the PPAs are recoverable through electric rates. The PPAs were approved by PURA on September 7, 2017. One contract was terminated on October 24, 2017, resulting in UI having twenty-one remaining contracts from this solicitation totaling approximately 70 MW.

In October of 2018, UI entered into five PPAs totaling approximately 50 MW from developers of offshore wind and fuel cell generation. These PPAs originated from an RFP issued by DEEP, under PA 17-144 which provides that the net costs of the PPAs are recoverable through electric rates. The PPAs were filed for PURA approval on October 25, 2018. On December 19, 2018, PURA issued its final decision approving the five PPAs and approved UI’s use of the non-bypassable federally mandated congestion charges for all customers to recover the net costs of the PPAs.

On December 28, 2018, DEEP issued a directive to UI to negotiate and enter into PPAs with twelve projects, totaling approximately 12 million MWh, selected as a result of the Zero Carbon RFP issued by DEEP pursuant to PA 17-3, which provides that the net costs of the PPAs are recoverable through electric rates. One of the selected projects is the Millstone nuclear facility located in Waterford, Connecticut which is owned by Dominion Energy, Inc. The PPA with Dominion was executed and approved by PURA in September 2019. Of the eleven other projects, one dropped out and PPAs with nine other projects were executed and approved by PURA in November 2019. The remaining PPA has been executed and submitted for approval to PURA.

Pursuant to Connecticut Act Concerning the Procurement of Energy Derived from Offshore Wind, DEEP solicited proposals from providers of energy derived from offshore wind facilities that are Class I renewable energy sources for up to 2,000 MW in the aggregate. In 2020, Pursuant to Connecticut Act Concerning the Procurement of Energy Derived From Offshore Wind, UI entered into a PPA with Vineyard Wind, an affiliate of UI, to provide 804 MW of offshore wind through the development of its Park City Wind Project. Similar to the case with the zero carbon PPAs discussed above, the net costs of the PPAs are recoverable through electric rates.

Reforming the Energy Vision

In 2014, the NYPSC instituted its REV proceeding, the goals of which are to improve electric system efficiency and reliability, encourage renewable energy resources, support distributed energy resources, or DER, and empower customer choice. In this proceeding, the NYPSC is examining the establishment of a Distributed System Platform to manage and coordinate DER, and provide customers with market data and tools to manage their energy use. The NYPSC is also examining how its regulatory practices should be modified to incentivize utility practices to promote REV objectives. REV has been divided into two tracks, Track 1 for market design and technology, and Track 2 for regulatory reform. REV proposes regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, and wider deployment of DER, such as micro grids, on-site power supplies and storage. Track 2 was undertaken in parallel with Track 1, and examines changes in current regulatory, tariff, market design and incentive structures to better align utility interests with achieving NYPSC's policy objectives. Our New York utilities are addressing related regulatory issues in their individual rate cases. A Track 2 order was issued in 2016 which included guidance related to the potential for earnings adjustment mechanisms, or EAMs, platform service revenues, innovative rate designs, and data utilization and security. In 2016, NYSEG and RG&E filed a proposal for the implementation of EAMs in the areas of system efficiency, energy efficiency, interconnections and clean air. The EAM is reflected in the rate plan approved in 2020.

In 2016, an initial DSIP was filed by NYSEG and RG&E and included information regarding the potential deployment of Automated Metering Infrastructure, or AMI. A separate petition for the cost recovery associated with full deployment of AMI was filed by NYSEG and RG&E. In March 2017, the NYPSC issued three separate REV-related orders. In July 2018, NYSEG and RG&E submitted an updated DSIP plan consistent with guidance received from the NY Department of Public Service. As of the end of 2018, both NYSEG and RG&E had deployed two energy storage projects each, consistent with the March 2017 NYPSC order requirements. In December 2018, the NYPSC staff submitted whitepapers on standby and buyback service rate design, future value stack compensation and capacity value compensation. The NYPSC ruled on the proposals set forth in the whitepapers on May 16, 2019. NYSEG and RG&E filed proposed standby and buyback rates with the NYPSC on September 24, 2019. The NYPSC also issued an order on value stack compensation for high-capacity-factor resources on December 12, 2019 modifying the treatment of certain high-capacity-factor DER in the Value Stack compensation framework. The modification per the December 12, 2019 Order became effective February 1, 2020. On March 19, 2020, the Commission issued an additional Order regarding Value Stack Compensation. The Order directs National Grid, NYSEG and RGE to reallocate capacity from closed tranches where available capacity remained due to projects being canceled since the issuance of the VDER Compensation Order, and to assign that capacity to a new Community Credit Tranche with compensation at 2 cents per kWh. The utilities must also continue to reallocate capacity to this new Tranche for the next six months when there are cancellations of projects that have received a Market Transition Credit (MTC) or Community Credit allocation. The new provisions per the March 19, 2020 Order became effective on May 1, 2020.

On May 14, 2020, the Commission issued an Order extending and expanding distributed solar incentives. In addition to authorizing the extension of and additional funding for the NY-Sun program, the Commission modified certain program rules related to the NY-Sun program and the VDER policy. As part of the ordered modifications, the Commission directed the electric utilities with VDER tariffs to add tariff language for a Remote Crediting program that will allow Value-Stack-eligible generation resources to distribute the credits they receive for generation injected into the utility system to the utility bills of multiple, separately sited, non-residential customers. The Commission ordered the utilities to submit tariff leaves that implement the modifications associated with the Remote Crediting program to become effective November 1, 2020. Given the complexity of the program changes, the utilities have petitioned the Commission for tariffs filings to be made on February 15, 2021, with an effective date of March 1, 2021.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2018 Winter Storms

In March 2018, following two severe winter storms that impacted over more than a million electric utility customers in New York, including 520,000 NYSEG and RG&E customers, the NYDPS commenced a comprehensive investigation of the preparation and response to those events by New York's major electric utility companies. The investigation was expanded in the spring of 2018 to include other 2018 New York spring storm events.

On April 18, 2019, the NYDPS staff issued a report or the 2018 Staff Report, of the findings from their investigation. The 2018 Staff Report identified 94 recommendations for corrective actions to be implemented in the utilities Emergency Response Plans, or ERPs. The report also identified potential violations by several of the utilities, including NYSEG and RG&E.

Also on April 18, 2019, the NYPSC issued an Order Instituting Proceeding and to Show Cause directed to all major electric utilities in New York, including NYSEG and RG&E. The order directs the utilities, including NYSEG and RG&E, to show cause why the NYPSC should not pursue civil and/or administrative penalties for the apparent failure to follow their respective ERPs as approved and mandated by the NYPSC. The NYPSC also directed the utilities, within 30 days, to address whether the NYPSC should mandate, reject or modify in whole or in part, the 94 recommendations contained in the 2018 Staff Report. On May 20, 2019, NYSEG and RG&E responded to the portion of the Order to Show Cause with respect to the recommendations contained in the 2018 Staff Report. A petition requesting Commission approval of a joint settlement agreement was filed with the Commission on December 17, 2019. On February 6, 2020, the Commission approved the joint settlement agreement, which allows the companies to avoid litigation and provides for payment by the companies of a $10.5 million penalty ($9.0 million by NYSEG and $1.5 million by RG&E). The settlement reached as part of the NYSEG Electric and RG&E Electric three-year rate plan provides for utilization of these penalties as rate modifiers by the establishment of regulatory liabilities that will be amortized over the three-year term of the rate plans for both NYSEG Electric and RG&E Electric.

New York State Public Service Commission Show Cause Order Regarding Greenlight Pole Attachments

On November 20, 2020, the NYPSC issued an Order Instituting Proceeding and to Show Cause, or the Show Cause Order, regarding alleged violations of the NYPSC's 2004 Order Adopting Policy Statement on Pole Attachments, dated August 6, 2004, or the 2004 Pole Order, by RG&E, Greenlight Networks, Inc., or Greenlight, and Frontier Communications, or Frontier. The alleged violations detailed in the Show Cause Order arise from Greenlight's installation of unauthorized and substandard communications attachments throughout RG&E's and Frontier's service territories. The Show Cause Order directs RG&E to show cause within 30 days why the NYPSC should not pursue civil and/or administrative penalties or initiate a prudency proceeding or civil action for injunctive relief for more than 11,000 alleged violations of the 2004 Pole Order. Under NY Public Service Law Section 25-a, each alleged violation carries a potential penalty of up to $100,000 where it can be shown that the violator failed to "reasonably comply" with a statute or NYPSC order.

RG&E, Greenlight and Frontier filed respective notices to initiate settlement negotiations with respect to the alleged violations and to extend the deadline for filing a response to the Show Cause Order. The NYPSC granted the extension requests initiating settlement discussions. We cannot predict the outcome of this matter.

CMP Customer Billing System Investigation and Class Action

On March 1, 2018, the MPUC issued a Notice of Investigation initiating a summary investigation into CMP's metering, billing, and customer communications practices. Due to the highly technical nature of CMP's customer billing system, on March 22, 2018 the MPUC issued an Order Initiating Audit commencing a forensic audit of CMP's customer billing system to identify any errors that have, or continue to be resulting in billing inaccuracies. On July 10, 2018, the MPUC issued an Order Modifying Scope of Audit, which expanded the scope of the audit to include CMP's customer communication practices. On December 20, 2018, the MPUC released the findings of the forensic audit of CMP's customer billing system and customer communication practices. On January 14, 2019, the MPUC issued an Order and Notice of Investigation initiating an investigation of CMP's metering and billing practices. On September 3, 2019, the MPUC issued its Bench Analysis in the Metering and Billing Investigation and supported the findings of the independent audit. On September 7, the OPA issued testimony and findings from a separate audit firm which agreed with certain portions of the independent audit and also stated that continuing problems still persist in CMP's billing system. CMP provided rebuttal testimony on October 16, 2019, and hearings were held in November 2019. On January 30, 2020, the MPUC Commissioners deliberated and based on the verbal discussion, the Commissioners indicated that CMP's Metering and Billing system is accurately reporting data; there is no systemic root cause for high usage complaints and errors related to CMP's metering and billing system are localized and random, not systemic. The Commissioners were critical of CMP finding that CMP failed to implement proper testing of the SmartCare system prior to go-live; CMP's implementation of SmartCare was imprudent; CMP's SmartCare implementation experienced an unacceptable number of billing errors, delayed or estimated bills, bill presentment issues and unreasonable time required to address these issues; and the implementation issues were compounded by inadequate staffing, resulting in the inability of customers to contact a CMP representative. On February 19, 2020, the MPUC issued an order in CMP's distribution rate case proceeding discussed above and on February 24, 2020 issued an order in the metering and billing investigation. Each order reflected the MPUC's conclusion that CMP's Metering and Billing system is accurately reporting data, there is no systemic root cause for high usage complaints and errors related to CMP's metering and billing system are localized and random, not systemic. However, the MPUC orders imposed a reduction of 100 basis points in ROE, as a management efficiency adjustment, to address the MPUC Commissioners' concerns with CMP's customer service implementation and performance following the launch of its new billing system in 2017. The management efficiency adjustment will remain in effect until CMP has demonstrated satisfactory customer service performance on four specified service quality measures for a rolling average period of 18 months, which commenced on March 1, 2020. CMP is meeting the required rolling average benchmarks on all four of these quality measures. On April 27, 2020, the MPUC issued an order requiring that CMP pay for the costs of the metering, billing and customer service practices audit, which were less than $1 million.

On August 16, 2018, an amended class action lawsuit was filed against CMP and the Company in the Cumberland County Superior Court on behalf of all CMP customers alleging that CMP's new billing software and metering system improperly overcharged customers. The plaintiff asserts this claim under the common law of unjust enrichment, breach of contract and fraudulent and intentional misrepresentation and seeks damages, punitive damages, attorney fees and costs. On September 21, 2018, we filed a Motion to Dismiss all of the claims that was opposed by the plaintiffs. On November 14, 2018, the plaintiff filed a motion for a preliminary and permanent injunction enjoining CMP from sending disconnection notices and/or disconnecting their power until this litigation is resolved. On February 22, 2019, the Cumberland County Superior Court ordered that the proceedings be stayed until November 1, 2019 to allow resolution of the MPUC's formal investigation of CMP's billing practices and denied the plaintiff's motion for a temporary restraining order. On July 30, 2019, Douglas Herling, chief executive officer of CMP, and Iberdrola, S.A. were added as defendants and additional claims alleging violations of the Racketeer Influenced and Corrupt Organizations Act were added to the case. CMP and the Company removed the case to federal court and filed a Motion to Dismiss on September 30, 2019. On November 22, 2019, upon agreement of the parties, CMP and the Company withdrew its motion to dismiss without prejudice and the plaintiffs were granted leave to file an amended complaint on or before January 31, 2020 to allow for the conclusion of the MPUC investigation into CMP's metering, billing, and customer communications practices. On January 30, 2020, the MPUC deliberated the metering, billing and customer communications investigation. The MPUC found that with exception of certain localized and random errors, CMP's billing system is working as designed and there were no systemic errors in billing. The decision also included an administrative process to address unresolved customer complaints of high bills. On January 31, 2020, the plaintiffs filed their third amended complaint. On February 28, 2020, CMP and the Company filed a Motion to Dismiss Plaintiff's Third Amended Complaint Without Prejudice or to Stay Proceedings Pending Plaintiffs' Exhaustion of Administrative Remedies which was denied on November 25, 2020. We cannot predict the outcome of this class action lawsuit.

CMP Disconnection Notices Investigation

On January 22, 2020, the MPUC initiated an investigation into certain customer notices of CMP that reference service disconnection. The purpose of this investigation is (1) to determine whether CMP provided customers notices that violated Commission rules or that contained incorrect or misleading information and, (2) if it did, to order CMP to show cause why it should not be subject to administrative penalties for those violations. CMP has responded to data requests and party testimony was filed on March 2, 2020. Hearings were suspended to allow for settlement discussions that began in March 2020. On April 27, 2020, CMP filed a proposed stipulation to resolve all issues in this proceeding and requested that the Hearing Examiner convene a settlement conference to discuss the proposed Stipulation. A settlement conference was held on April 30, 2020 and May 5, 2020. A revised Stipulation was filed with the MPUC on May 8, 2020, and was deliberated and rejected by the MPUC on June 2, 2020, due to the Office of the Public Advocate's lack of authority to perform the tasks required by the revised Stipulation. A written order rejecting the Stipulation was issued on June 8, 2020. Following submission of an offer of proof by the customer-intervenors, comments by CMP and the Office of the Public Advocate and recommendations by the MPUC staff, the MPUC issued an Order on August 5, 2020, accepting CMP's consent to a finding that CMP violated a MPUC rule and payment of an administrative penalty less than $1 million.

CMP Revenue Decoupling Mechanism Investigation

On June 9, 2020, the MPUC issued a Notice of Investigation to open an investigation into the effects of the COVID-19 pandemic on customers' electricity-usage patterns and whether CMP's RDM should be suspended for the annual distribution rate change that is expected to occur on July 1, 2021, for electricity delivered in calendar year 2020. On June 24, 2020, the MPUC issued a procedural order setting forth initial steps in this proceeding. On July 21, 2020, CMP filed testimony presenting electricity-usage data for its two RDM classes (residential and commercial/industrial) through June 2020, along with testimony explaining the data and the reasons why the current RDM should remain in place without alteration. On August 11, 2020, a technical conference was held and CMP filed electricity-usage data on August 20, 2020. On December 16, 2020, the MPUC issued an Order determining that CMP's RDM should not be suspended and the RDM should be simplified by merging the two RDM classes into a single class. There is no impact to existing RDM balances as a result of the order issued by the MPUC.

CMP Annual Compliance Filing

On March 31, 2020, CMP submitted its annual compliance filing in accordance with the Commission's February 19, 2020 decision in *Public Utilities Commission, Investigation into Rates and Revenue Requirements of Central Maine Power Company*. In its filing, CMP proposed an overall increase in its distribution delivery revenues of $14.5 million, or 5.6% over current rates, effective July 1, 2020. This increase is due primarily to storm costs and RDM, which are offset by excess deferred income taxes. As a result of the COVID-19 pandemic, CMP's filing proposed cost recovery provisions designed to minimize the rate impacts on customers including, without limitation, an extended period for recovery of storm costs incurred in 2019. On June 18, 2020, the MPUC approved a partial stipulation, which adopted CMP's proposal to recover 2019 major storm costs over a three-year period commencing on July 1, 2020, but denied CMP's proposed recovery of costs related to its legacy billing system, which are less than $1 million. On June 18, 2020, CMP made a compliance filing with revised tariffs, which was approved by the MPUC on June 23, 2020, and the new rates took effect on July 1, 2020.

CMP Standard Offer Uncollectible Adder Investigation

On August 19, 2020, the MPUC issued a Notice of Investigation to open an investigation into the whether the uncollectible adder to CMP's standard offer retainage account for the residential and small non-residential standard offer customer class should be increased for standard offer electricity-supply rates that will go into effect January 1, 2022. The investigation will also include a review of CMP's credit and collection practices. A technical conference was held on October 8, 2020. On December 4, 2020, the MPUC Staff issued a Bench Analysis proposing an imprudent disallowance adjustment of approximately $4.5 million to the uncollectible adder retainage account reflecting CMP's alleged imprudence in its implementation of its new billing system and credit and collection practices. CMP filed testimony in response to the Bench Analysis on February 5, 2021. We cannot predict the outcome of this matter.

Tax Act Proceedings

The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC, MPUC, PURA, DPU and the FERC have instituted separate proceedings in New York, Maine, Connecticut, Massachusetts and the FERC, respectively, to review and address the implications of the Tax Act on the utilities.

In New York, the NYPSC issued an order requiring sur-credits to return benefits reflecting the lower effective tax rate of 21% to customers effective October 1, 2018. For NYSEG Gas, RG&E Electric and RG&E Gas the NYPSC also required the sur-credit to include the return to customers of the January - September 2018 Tax Act savings over three years. The remaining deferred amounts associated with the recognition of the effects of the Tax Act are being used as rate moderators in the approved 2020 Joint Proposal. In Connecticut, UI and SCG expect Tax Act savings to be deferred until they are reflected in tariffs in a future rate case, unless PURA determines otherwise. CNG and BGC include Tax Act savings in their current rate plans. In Maine, CMP adjusted rates beginning July 1, 2018 to pass back to customers the Tax Act savings after offsetting for recovery of deferred 2017 storm costs and in the general rate case filing with the MPUC is proposing to use savings arising out of the Tax Act to minimize rate increases while making its electric system more reliable. In its February 19, 2020 order in the CMP's distribution rate case proceeding discussed above, the MPUC approved CMP's distribution related accumulated deferred income tax balances associated with the Tax Act as well as the authorized amortization periods for the return of regulatory liabilities and the recovery regulatory assets. At the FERC, CMP transmission and UI transmission adjusted their tariffs in June 2018 to reflect the income statement value of Tax Act savings.

Power Tax Audits

Previously, CMP, NYSEG and RG&E implemented Power Tax software to track and measure their respective deferred tax amounts. In connection with this change, we identified historical updates needed with deferred taxes recognized by CMP, NYSEG and RG&E and increased our deferred tax liabilities, with a corresponding increase to regulatory assets, to reflect the updated amounts calculated by the Power Tax software. Since 2015, the NYPSC and MPUC accepted certain adjustments to deferred taxes and associated regulatory assets for this item in recent distribution rate cases, resulting in regulatory asset balances of approximately $148 million and $153 million, respectively, for this item at December 31, 2020 and December 31, 2019.

In 2017, audits of the power tax regulatory assets were commenced by the NYPSC and MPUC. On January 11, 2018, the NYPSC issued an order opening an operations audit on NYSEG and RG&E and certain other New York utilities regarding tax accounting. The NYPSC audit report is expected to be completed during 2021. In January 2018, the MPUC published the Power Tax audit report with respect to CMP, which indicated the auditor was unable to verify the asset "acquisition value" used to calculate the Power Tax regulatory asset. CMP responded to the audit report in its rate case filing by providing additional acquisition value support and, therefore, requested full recovery of the Power Tax regulatory asset. The MPUC had an outside firm conduct an audit of CMP's filing and acquisition values, and the auditor found CMP's information was reasonable. In September 2019, CMP filed a report in response to the audit report and addressed MPUC staff concerns. On December 17, 2019, CMP filed a stipulation with the MPUC providing for recovery of the Power Tax regulatory asset and adjusting the carrying costs values for the period of July 1, 2017 through June 30, 2019. The MPUC approved the stipulation on January 21, 2020 and CMP began collecting the Power Tax Regulatory asset in July 2020 over 32.5 years.

Weather Impact

The demand for electric power and natural gas is affected by seasonal differences in the weather. Statewide demand for electricity in New York, Connecticut and Maine tends to increase during the summer months to meet cooling load or in winter months for heating load while statewide demand for natural gas tends to increase during the winter to meet heating load. Market prices for both electricity and natural gas reflect the demand for these products and their availability at that time. Overall operating results of Networks do not fluctuate due to commodity costs as the regulated utilities generally recover those costs coincident with their expense or defer any differences for future recovery. Networks has historically sold less power when weather conditions are milder and may also be affected by severe weather, such as ice and snow storms, hurricanes and other natural disasters which may result in additional cost or loss of revenues that may not be recoverable from customers. However, Networks' regulated utilities, other than MNG, have approved RDMs as part of the NYPSC, PURA and MPUC rate plans in place for the period ended December 31, 2020. The RDM allows the regulated utilities to defer for future recovery and shortfall from projected revenues whether due to weather, economic conditions, conservation or other factors.

New Renewable Source Generation

Under Connecticut Public Act 11-80, or PA, Connecticut electric utilities are required to enter into long-term contracts to purchase Connecticut Class I Renewable Energy Certificates, or RECs, from renewable generators located on customer premises. Under this program, UI is required to enter into contracts totaling approximately $200 million in commitments over approximately 21 years. The obligations were initially expected to phase in over a six-year solicitation period and to peak at an annual commitment level of about $13.6 million per year after all selected projects are online. PA 17-144, PA 18-50 and PA 19-35 extended the original six-year solicitation period of the program by adding seventh, eighth, ninth, and tenth years, and increased the original funding level of this program by adding up to $64 million in additional commitments by UI. UI expects to partially mitigate the cost of these contracts through the resale of the RECs. PA 11-80 provides that the remaining costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

Pursuant to Connecticut statute, in January 2017, UI entered into a master agreement with the Connecticut Green Bank to procure Connecticut Class I RECs produced by residential solar installations in 15-year tranches, with a final tranche to commence no later than 2022. UI's contractual obligation is to procure 20% of RECs produced by about 255 MW of residential solar installations. Connecticut statutes provides that the net costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

Pursuant to Maine law, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or RECs, from qualifying resources. The MPUC is further authorized to order Maine transmission and distribution utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen's 60 Megawatt (MW) Rollins wind farm. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. Pursuant to a MPUC Order dated December 18, 2017, CMP entered into a 20-year agreement with Dirigo Solar, LLC on September 10, 2018, to purchase capacity and energy from multiple Dirigo solar facilities throughout CMP's service territory. CMP's purchase obligations under the Dirigo contract will increase as additional solar facilities are brought on line, eventually reaching a level of approximately $4 million per year. Pursuant to a MPUC Order dated November 6, 2019, CMP entered into a 20-year agreement with Maine Aqua Ventus I GP LLC on December 9, 2019, to purchase capacity and energy from an off-shore wind under development near Monhegan Island, Maine. CMP's purchase obligations under the Maine Aqua Ventus contract will be approximately $12 million per year once the facility begins commercial operation. Pursuant to Maine law, the MPUC must conduct two competitive solicitation processes to procure, in the aggregate, an amount of energy or RECs from Class 1A resources that is equal to 14% of retail electricity sales in the State during calendar year 2018, or 1.715 million MWh. Of that 14% total, the MPUC must acquire at least 7%, but not more than 10%, through contracts approved by December 31, 2020 (Tranche 1), and acquire the remaining amount (Tranche 2) through a solicitation process that started on January 15, 2021. Pursuant to Maine law, on September 23, 2020, the MPUC issued an order accepting term sheet proposals from 14 projects in CMP's service territory and ordered the MPUC Staff and CMP to negotiate and execute contracts to implement the accepted terms. As of December 31, 2020, one project has withdrawn from the solicitation and CMP has executed contracts with 5 of the remaining 13 projects for 20-year terms. In accordance with MPUC orders, CMP either sells the purchased energy from these facilities in the ISO New England markets or periodically auctions the purchased output to wholesale buyers in the New England regional market. Under Maine law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under Maine law, and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

Renewables

Renewable Energy Incentives

Renewables relies, in part, upon government policies that support utility-scale renewable energy and enhance the economic feasibility of development and operating wind energy projects in regions in which Renewables operates or plans to develop and operate renewable energy facilities.

On December 20, 2019, the Setting Every Community up for Retirement Enhancement Act of 2019 was signed into law that extended the PTC and investment tax credit, or ITC, options for wind facilities to 60% of the full credit for facilities commencing construction in 2020, leaving in place phased down credits for projects commencing in years prior to 2020.

The 2020 Consolidated Appropriations Act provides favorable extensions to renewable income tax incentives. Onshore and offshore wind projects may now claim a 60% PTC for projects commencing construction in 2020 and 2021. In addition, offshore wind may now elect to claim a 30% ITC for projects commencing construction through 2025. Onshore wind can claim an 18% ITC for projects commencing construction in 2020 or 2021, with no ITC thereafter.

Solar projects commencing construction before 2020 may claim a 30% ITC. Solar projects that commence construction from 2020-2022 may claim a 26% ITC, projects commencing construction in 2023 may claim a 22% ITC and projects commencing thereafter may claim a 10% ITC. The ITC statutes require solar projects be completed by the end of 2025 in order to claim the applicable ITCs.

The Internal Revenue Service, or IRS, provided continuity safe harbor guidance that requires renewable projects to be completed within four years of the year construction commences. Any projects that do not meet this requirement will fall outside of the safe harbor and be subject to IRS scrutiny with regard to the date construction commenced. In 2020, the IRS allowed projects beginning construction in 2016 or 2017 an additional year (five years total) to complete construction. In late December 2020, the IRS issued a notice giving onshore wind projects on federal lands, with transmission permit requirements, and offshore wind projects 10 years to complete construction.

Results of Operations

The following table sets forth financial information by segment for each of the periods indicated. During the year ended December 31, 2020, we identified various immaterial corrections to prior periods primarily related to property, plant and equipment and deferred tax liabilities that originated in prior periods. Accordingly, we have reflected the correction of these prior period amounts in the periods in which they originated.

	Year Ended December 31, 2020			
	Total	Networks	Renewables	Other(1)
	(in millions)			
Operating Revenues	**$ 6,320**	**$ 5,188**	**$ 1,132**	**$ —**
Operating Expenses				
Purchased power, natural gas and fuel used	1,379	1,125	254	—
Operations and maintenance	2,466	2,038	429	(1)
Depreciation and amortization	987	592	394	1
Taxes other than income taxes	619	556	71	(8)
Total Operating Expenses	**5,451**	**4,311**	**1,148**	**(8)**
Operating Income	**869**	**877**	**(16)**	**8**
Other Income (Expense)				
Other income (expense)	18	15	15	(12)
Losses (earnings) from equity method investments	(3)	10	(13)	—
Interest expense, net of capitalization	(316)	(234)	(7)	(75)
Income Before Income Tax	**568**	**668**	**(21)**	**(79)**
Income tax expense (benefit)	29	120	(80)	(11)
Net Income (Loss)	**539**	**548**	**59**	**(68)**
Net loss (income) attributable to noncontrolling interests	42	(2)	44	—
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 581**	**$ 546**	**$ 103**	**$ (68)**

	Year Ended December 31, 2019			
	Total	Networks	Renewables	Other(1)
	(in millions)			
Operating Revenues	**$ 6,336**	**$ 5,164**	**$ 1,184**	**$ (12)**
Operating Expenses				
Purchased power, natural gas and fuel used	1,509	1,249	260	—
Operations and maintenance	2,305	1,932	392	(19)
Depreciation and amortization	933	549	383	1
Taxes other than income taxes	591	544	56	(9)
Total Operating Expenses	**5,338**	**4,274**	**1,091**	**(27)**
Operating Income	**998**	**890**	**93**	**15**
Other Income (Expense)				
Other income (expense)	121	(15)	155	(19)
Earnings (losses) from equity method investments	3	11	(8)	—
Interest expense, net of capitalization	(310)	(269)	(14)	(27)
Income Before Income Tax	**812**	**617**	**226**	**(31)**
Income tax expense (benefit)	169	152	28	(11)
Net Income (Loss)	**643**	**465**	**198**	**(20)**
Net loss (income) attributable to noncontrolling interests	24	(2)	26	—
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 667**	**$ 463**	**$ 224**	**$ (20)**

	Year Ended December 31, 2018			
	Total	Networks	Renewables	Other(1)
	(in millions)			
Operating Revenues	**$ 6,477**	**$ 5,310**	**$ 1,138**	**$ 29**
Operating Expenses				
Purchased power, natural gas and fuel used	1,653	1,423	228	2
Operations and maintenance	2,258	1,887	369	2
Loss from assets held for sale	16	—	—	16
Depreciation and amortization	855	503	352	—
Taxes other than income taxes	579	529	57	(7)
Total Operating Expenses	**5,361**	**4,342**	**1,006**	**13**
Operating Income (Loss)	**1,116**	**968**	**132**	**16**
Other Income (Expense)				
Other (expense) income	(66)	(79)	18	(5)
Earnings (losses) from equity method investments	10	13	(3)	—
Interest expense, net of capitalization	(303)	(260)	(33)	(10)
Income Before Income Tax	**757**	**642**	**114**	**1**
Income tax expense (benefit)	167	167	(32)	32
Net Income (Loss)	**590**	**475**	**146**	**(31)**
Net income attributable to noncontrolling interests	(3)	(2)	(1)	—
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 587**	**$ 473**	**$ 145**	**$ (31)**

(1)Other amounts represent Corporate, Gas (only in 2018) and intersegment eliminations.

Comparison of Period to Period Results of Operations

Operating revenues decreased by less than 1%, from $6,336 million for the year ended December 31, 2019, to $6,320 million for the year ended December 31, 2020.

Purchased power, natural gas and fuel used decreased by 9%, from $1,509 million for the year ended December 31, 2019, to $1,379 million for the year ended December 31, 2020.

Operations and maintenance increased by 7%, from $2,305 million for the year ended December 31, 2019, to $2,466 million for the year ended December 31, 2020.

Details of the period to period comparison are described below at the segment level.

Year Ended December 31, 2020 Compared to the Year Ended December 31, 2019

Networks

Operating revenues for the year ended December 31, 2020 increased by $24 million, or less than 1%, from $5,164 million for the year ended December 31, 2019, to $5,188 million. Electricity and gas revenues increased by $60 million, primarily due to the impact of increased customer rates for the year ended December 31, 2020 compared to the same period of 2019 and increased by $26 million primarily due to make whole period revenue adjustment from new rate case activity in NY. Electricity and gas revenues also increased by $24 million due to higher transmission revenues, negative revenues adjustments in 2019 totaling $16 million related to earnings sharing, net plant reconciliation and other regulatory deferrals and $3 million of other increases. These were offset by a decrease of $10 million from a pension deferral write-off and a $10 million decrease from the inability to charge late payment fees due to regulatory orders. Electricity and gas revenues changed due to the following items that have offsets within the income statement: a decrease of $124 million in purchased power and purchased gas (offset in purchased power), a decrease of $42 million which is offset in income taxes. These were offset by an increase of $69 million of amortizations that are offset in operating expenses and an increase of $12 million in taxes other than income taxes.

Purchased power, natural gas and fuel used for the year ended December 31, 2020 decreased by $124 million, or 10%, from $1,249 million for the year ended December 31, 2019, to $1,125 million. The decrease is primarily driven by a $131 million decrease in average commodity prices and an overall decrease in electricity and gas units procured due to a decline in degree days offset by a $7 million increase in other power supply purchases in the period.

Operations and maintenance during the year ended December 31, 2020 increased by $106 million, or 5%, from $1,932 million for the year ended December 31, 2019, to $2,038 million. The increase is driven by $22 million in increased salaries due to additional headcount offset by favorable capitalized labor, a $10 million increase in outage restoration costs, a $7 million increase in uncollectible expenses, a $6 million increase due to additional cleaning and personal protective equipment resulting from COVID-19, an increase of $69 million in amortizations (which are offset in revenue) and a $2 million increase in Other. These were offset by a decrease of $5 million in unfavorable write-off of deferred storm costs in the year ended December 31, 2019, which did not recur in 2020 and a decrease of $5 million in favorable overhead.

Renewables

Operating revenues for the year ended December 31, 2020 decreased by $52 million, or 4% from $1,184 million for the year ended December 31, 2019, to $1,132 million. The decrease in operating revenues was primarily due to unfavorable MtM changes of $69 million on energy derivative transactions entered for economic hedging purposes, a decrease of $26 million in merchant pricing, a $34 million decrease in thermal revenue driven by lower volumes and average prices in the period, and a $7 million decrease in other revenues (offset in operating expenses). These were offset by an increase of $85 million driven by wind generation output increase of 1,790 GWh from existing and new capacity in the current period.

Purchased power, natural gas and fuel used for the year ended December 31, 2020 decreased by $6 million, or 2%, from $260 million for the year ended December 31, 2019, to $254 million. The decrease is primarily driven by a decrease of $28 million in thermal purchases driven by the decrease in volume and unit cost in the period, offset by an increase of $5 million in power purchases, $5 million in RECs and unfavorable MtM changes on derivatives of $11 million due to market price changes in the period.

Operations and maintenance for the year ended December 31, 2020 increased by $37 million, or 9%, from $392 million for the year ended December 31, 2019, to $429 million. The increase is primarily due to $36 million of increased costs resulting from higher personnel and maintenance costs, which are primarily attributed to new capacity. Additionally, operations and maintenance expense increased by $11 million driven by a favorable asset retirement obligation adjustment in 2019, offset by a $3 million decrease due to a favorable provision release in the year ended December 31, 2020, and $7 million in lower other expenses (offset in operating revenues).

Depreciation, Amortization and Impairment

Depreciation, amortization and impairment expenses for the year ended December 31, 2020 increased by $54 million, or 6%, from $933 million for the year ended December 31, 2019, to $987 million. The increase is driven by $71 million from plant additions in Networks and Renewables in the period, an increase in lease amortizations of $3 million and a $4 million increase due to a favorable asset retirement obligation adjustment for the year ended December 31, 2019, offset by a $24 million decrease of accelerated depreciation from the repowering of wind farms in Renewables.

Other Income and (Expense) and Equity Earnings

Other income and (expense) and equity earnings for the year ended December 31, 2020 decreased by $109 million, or 88%, from $124 million for the year ended December 31, 2019, to $15 million. The decrease is primarily due to a $134 million gain from the sale of assets in Renewables recorded in 2019 and $6 million of unfavorable equity earnings in the period, offset by a $20 million gain from the sale of assets in the year ended December 31, 2020 in Renewables and Networks and an $11 million penalty incurred in the same period of 2019 in Networks.

Interest Expense, Net of Capitalization

Interest expense for the year ended December 31, 2020 increased by $6 million or 2% from $310 million for the year ended December 31, 2019, to $316 million. Networks had an $18 million decrease in carrying costs on regulatory deferrals during the period. Renewables interest expense decreased by $5 million due to lower average debt balances in the current period. This is offset by an interest expense increase in Other of $28 million primarily from new debt issued in 2020 and 2019.

Income Tax Expense

The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2020 was 5.1%, which is below the federal statutory tax rate of 21%, primarily due to the recognition of production tax credits associated with wind production and the effect of the excess deferred tax amortization resulting from the Tax Act (offset in revenue). The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2019, was 20.8%, which is below the federal statutory tax rate of 21%, primarily due to the recognition of production tax credits associated with wind production and favorable discrete tax adjustments.

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Networks

Operating revenues for the year ended December 31, 2019 decreased by $146 million, or 3%, from $5,310 million for the year ended December 31, 2018, to $5,164 million. Operating revenues changed due to the following items that have offsets within the income statement: decrease of $174 million in purchased power and purchased gas in the same period (offset in purchased power), $43 million decrease in recoverable pension expense (offset in other expenses), an $11 million increase in property taxes (offset in taxes other than income taxes) and a $19 million increase in pass-through components, which are offset in operating expenses. Electricity and gas revenues increased by $48 million, primarily due to the impact of increased customer rates for the year ended December 31, 2019 compared to the same period of 2018. Electric and gas revenues decreased by $12 million due to higher earnings sharing during 2019 compared to the same period of 2018 and a $5 million increase in other.

Purchased power, natural gas and fuel used for the year ended December 31, 2019 decreased by $174 million, or 12%, from $1,423 million for the year ended December 31, 2018, to $1,249 million. The decrease is primarily driven by a $164 million decrease in average commodity prices and an overall decrease in electricity and gas units procured due to a decline in degree days combined with a $10 million decrease in other power supply purchases in the period, offset within operating revenues.

Operations and maintenance during the year ended December 31, 2019 increased by $45 million, or 2%, from $1,887 million for the year ended December 31, 2018, to $1,932 million. Operations and maintenance expense changed due to a $19 million increase in pass through components (offset in revenue), a $12 million increase in non-deferrable outage restoration costs and an $18 million increase in personnel costs (net of capitalized staff costs) driven by headcount and overtime increases, offset by $3 million decrease in other.

Renewables

Operating revenues for the year ended December 31, 2019 increased by $46 million, or 4% from $1,138 million for the year ended December 31, 2018, to $1,184 million. Operating revenues increased due to favorable MtM changes of $99 million on energy derivative transactions entered into for economic hedging purposes, an increase in wind production of $22 million from new capacity, an increase in thermal revenues of $28 million driven by higher average prices in the period and increased sales from Klamath (28% volume increase). These items were offset by an $69 million decrease due to prices decreasing 14% through a combination of lower merchant pricing, an adverse PPA mix, expired PPA contracts; a gain of $30 million from the sale of claims from a bankruptcy proceeding with a customer recorded in 2018; and a $4 million decrease in other revenues.

Purchased power, natural gas and fuel used for the year ended December 31, 2019 increased by $32 million, or 14%, from $228 million for the year ended December 31, 2018, to $260 million. The increase is primarily driven by an increase of $28 million and $6 million in power and thermal purchases, respectively, driven by the increase in volume and unit cost in the period, offset by favorable MtM changes on derivatives of $2 million due to market price changes in the current period.

Operations and maintenance for the year ended December 31, 2019 increased by $23 million or 6% from $369 million for the year ended December 31, 2018, to $392 million. The increase is primarily due to $34 million of increased costs resulting from headcount increases and higher maintenance costs, which are primarily attributed to growth and enhanced maintenance to increase availability. Additionally, operations and maintenance expense decreased by $11 million driven by an asset retirement obligation adjustment in 2019.

Depreciation, Amortization and Impairment

Depreciation, amortization and impairment expenses for the year ended December 31, 2019 increased by $62 million or 7% from $871 million for the year ended December 31, 2018, to $933 million. The increase is primarily due to increases of $47 million as a result of plant additions in Networks and Renewables in the period, increase of $31 million driven by accelerated depreciation from the repowering of wind farms in Renewables, offset by a loss of $16 million from remeasurement of assets held for sale driven by final purchase price negotiations and certain related working capital adjustments of Gas business recorded in 2018.

Other Income and (Expense) and Equity Earnings

Other income and (expense) and equity earnings for the year ended December 31, 2019 increased by $180 million, or 321%, from $(56) million for the year ended December 31, 2018, to $124 million, primarily due to a $30 million favorable change in allowance for funds used during construction, $43 million of favorable pension and other post-retirement expense in the period in Networks driven by lower actuarial loss amortization (offset in Networks revenue) and a $134 million gain from the sale of assets during the period in Renewables, offset by a decrease of $7 million in equity earnings, $11 million settlement penalty with the NYDPS in Networks and a decrease of $10 million driven by the write-off of certain development projects in Renewables in the current period.

Interest Expense, Net of Capitalization

Interest expense for the year ended December 31, 2019 increased by $7 million or 2% from $303 million for the year ended December 31, 2018, to $310 million. Networks had a $9 million increase in interest expense due to a higher average outstanding balance of debt in the period, partially offset by an $8 million decrease in carrying costs on regulatory deferrals. Other added $26 million of interest expense from new debt issued in 2019. This is offset by an interest expense decrease in Renewables of $20 million due to lower average debt balances in the current period.

Income Tax Expense

The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2019 was 20.8%, which is below the federal statutory tax rate of 21%, primarily due to the recognition of production tax credits associated with wind production and favorable discrete tax adjustments. The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2018, was 22.1%, which is higher than the 21% statutory federal income tax rate, predominantly due to $21 million of tax expense recorded in connection with the disposal of the Gas business and discrete adjustments recorded during the period, offset by the recognition of production tax credits associated with wind production.

Non-GAAP Financial Measures

To supplement our consolidated financial statements presented in accordance with U.S. GAAP, we consider adjusted net income and adjusted earnings per share as non-GAAP financial measures that are not prepared in accordance with U.S. GAAP. The non-GAAP financial measures we use are specific to AVANGRID and the non-GAAP financial measures of other companies may not be calculated in the same manner. We use these non-GAAP financial measures, in addition to U.S. GAAP measures, to establish operating budgets and operational goals to manage and monitor our business, evaluate our operating and financial performance and to compare such performance to prior periods and to the performance of our competitors. We believe that presenting such non-GAAP financial measures is useful because such measures can be used to analyze and compare profitability between companies and industries by eliminating the impact of certain non-cash charges. In addition, we present non-GAAP financial measures because we believe that they and other similar measures are widely used by certain investors, securities analysts and other interested parties as supplemental measures of performance.

We define adjusted net income as net income adjusted to exclude restructuring charges, mark-to-market earnings from changes in the fair value of derivative instruments, loss from held for sale measurement, accelerated depreciation derived from repowering of wind farms, impact of the Tax Act, costs incurred related to the PNMR Merger, a legal settlement, costs incurred in connection with the COVID-19 pandemic and adjustments for the non-core Gas storage business. We believe adjusted net income is more useful in understanding and evaluating actual and projected financial performance and contribution of AVANGRID core lines of business and to more fully compare and explain our results. The most directly comparable U.S. GAAP measure to adjusted net income is net income. We also define adjusted earnings per share, or adjusted EPS, as adjusted net income converted to an earnings per share amount.

The use of non-GAAP financial measures is not intended to be considered in isolation or as a substitute for, or superior to, AVANGRID's U.S. GAAP financial information, and investors are cautioned that the non-GAAP financial measures are limited in their usefulness, may be unique to AVANGRID and should be considered only as a supplement to AVANGRID's U.S. GAAP financial measures. The non-GAAP financial measures may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools.

Non-GAAP financial measures are not primary measurements of our performance under U.S. GAAP and should not be considered as alternatives to operating income, net income or any other performance measures determined in accordance with U.S. GAAP.

The following tables provide a reconciliation between Net Income attributable to AVANGRID and adjusted net income (non-GAAP) by segment for the years ended December 31, 2020, 2019 and 2018, respectively:

	Year Ended December 31, 2020			
	Total	**Networks**	**Renewables**	**Corporate ***
	(in millions)			
Net Income Attributable to Avangrid, Inc.	**$ 581**	**$ 546**	**$ 103**	**$ (67)**
Adjustments:				
Mark-to-market adjustments - Renewables	5	—	5	—
Restructuring charges	6	5	1	—
Accelerated depreciation from repowering	9	—	9	—
Impact of COVID-19	29	26	1	2
Merger costs	6	—	—	6
Legal settlement - Gas storage	5	—	—	5
Income tax impact of adjustments (1)	(16)	(8)	(4)	(3)
Adjusted Net Income (2)	**$ 625**	**$ 568**	**$ 115**	**$ (58)**

	Year Ended December 31, 2019			
	Total	**Networks**	**Renewables**	**Corporate ***
	(in millions)			
Net Income Attributable to Avangrid, Inc.	**$ 667**	**$ 463**	**$ 224**	**$ (20)**
Adjustments:				
Mark-to-market adjustments - Renewables	$ (76)	$ —	$ (76)	$ —
Restructuring charges	$ 6	$ 3	$ 1	$ 3
Accelerated depreciation from repowering	$ 33	$ —	$ 33	$ —
Income tax impact of adjustments (1)	$ 10	$ (1)	$ 11	$ (1)
Adjusted Net Income (2)	**$ 640**	**$ 465**	**$ 193**	**$ (17)**

	Year Ended December 31, 2018				
	Total	**Networks**	**Renewables**	**Corporate ***	**Gas Storage**
	(in millions)				
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 587**	**$ 473**	**$ 145**	**$ (12)**	**$ (19)**
Adjustments:					
Mark-to-market adjustments - Renewables	25	—	25	—	—
Restructuring charges	4	4	—	—	—
Loss from held for sale measurement	16	—	—	—	16
Impact of the Tax Act	46	5	16	25	—
Accelerated depreciation from repowering	3	—	3	—	—
Income tax impact of adjustments (1)	6	(1)	(7)	—	14
Gas Storage, net of tax	(11)	—	—	—	(11)
Adjusted Net Income (2)	**$ 676**	**$ 481**	**$ 182**	**$ 13**	**$ —**

(1) Income tax impact of adjustments: $(1) million from MtM adjustment, $(2) million from accelerated depreciation, $(2) million from restructuring charges, $(8) million from COVID-19 impacts, $(1) million from legal settlement - gas storage and $(2) million from merger costs for the year ended December 31, 2020. $20 million from MtM adjustment, $(9) million from accelerated depreciation, $(2) million from restructuring charges, for the year ended December 31, 2019. $(6) million from MtM adjustment, $(1) million from accelerated depreciation, $(1) million from restructuring charges, $14 million from loss from held for sale measurement for the year ended December 31, 2018.

(2) Adjusted Net Income is a non-GAAP financial measure and is presented after excluding restructuring charges, loss from held for sale measurement, impact of the Tax Act, accelerated depreciation derived from the repowering wind farms, MtM activities in Renewables, costs incurred related to the PNMR Merger, costs incurred in connection with the COVID-19 pandemic, merger costs and the Gas storage businesses.

* Includes Corporate and other non-regulated entities as well as intersegment eliminations.

Comparison of Period to Period Results of Operations

Year Ended December 31, 2020 Compared to the Year Ended December 31, 2019

Adjusted net income

Adjusted net income decreased by $15 million, or 2%, from $640 million for the year ended December 31, 2019 to $625 million for the year ended December 31, 2020. The decrease is primarily due to a $77 million decrease in Renewables as a result of gain from the sale of assets in 2019 that did not recur in 2020, a $41 million decrease in Corporate mainly driven by higher interest expenses in the period, offset by $103 million increase in Networks driven primarily by approved rate cases in the period.

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Adjusted net income

Adjusted net income decreased by $35 million, or 5%, from $676 million for the year ended December 31, 2018 to $640 million for the year ended December 31, 2019. The decrease is primarily due to a $16 million decrease in Networks driven by increased non-deferrable outage restoration costs and an increase in personnel costs (net of capitalized staff costs) driven by headcount and overtime increases and a $30 million decrease in Corporate mainly driven by higher interest expense, offset by a $11 million increase in Renewables driven mainly by thermal revenue increase and a gain from the sale of assets and associated change in control during the period.

The following tables reconcile Net Income attributable to AVANGRID to Adjusted Net Income (non-GAAP), and EPS attributable to AVANGRID to adjusted EPS (non-GAAP) for the years ended December 31, 2020, 2019 and 2018, respectively:

	Year Ended December 31,		
	2020	**2019**	**2018**
	(in millions)		
Networks	$ 546	$ 463	$ 473
Renewables	103	224	145
Corporate (1)	(67)	(20)	(12)
Gas Storage	—	—	(19)
Net Income	**$ 581**	**$ 667**	**$ 587**
Adjustments:			
Mark-to-market adjustments - Renewables (2)	5	(76)	25
Restructuring charges (3)	6	6	4
Loss from held for sale measurement (4)	—	—	16
Impact of the Tax Act (5)	—	—	46
Accelerated depreciation from repowering (6)	9	33	3
Impact of COVID-19 (7)	29	—	—
Merger costs (8)	6	—	—
Legal settlement - Gas storage (9)	5	—	—
Income tax impact of adjustments	(16)	10	6
Gas Storage, net of tax (9)	—	—	(11)
Adjusted Net Income (10)	**$ 625**	**$ 640**	**$ 676**

	Year Ended December 31,		
	2020	2019	2018
Networks	$ 1.76	$ 1.50	$ 1.53
Renewables	0.33	0.72	0.47
Corporate (1)	(0.22)	(0.06)	(0.04)
Gas Storage	—	—	(0.06)
Earnings Per Share	**$ 1.88**	**$ 2.16**	**$ 1.90**
Adjustments:			
Mark-to-market adjustments - Renewables (2)	0.02	(0.25)	0.08
Restructuring charges (3)	0.02	0.02	0.01
Loss from held for sale measurement (4)	—	—	0.05
Impact of the Tax Act (5)	—	—	0.15
Accelerated depreciation from repowering (6)	0.03	0.11	0.01
Impact of COVID-19 (7)	0.09	—	—
Merger costs (8)	0.02	—	—
Legal settlement - Gas storage (9)	0.01	—	—
Income tax impact of adjustments	(0.05)	0.03	0.02
Gas Storage, net of tax (9)	—	—	(0.04)
Adjusted Earnings Per Share (10)	**$ 2.02**	**$ 2.07**	**$ 2.18**

(1) Includes corporate and other non-regulated entities as well as intersegment eliminations.
(2) Mark-to-market earnings relates to earnings impacts from changes in the fair value of Renewables' derivative instruments associated with electricity and natural gas.
(3) Restructuring and severance related charges relate to costs resulting from restructuring actions involving initial targeted voluntary workforce reductions and related costs in our plan to vacate a lease, predominantly within the Networks segment and costs to implement an initiative to mitigate costs and achieve sustainable growth.
(4) Represents loss from measurement of assets and liabilities held for sale in connection with the sale of the gas trading and storage businesses.
(5) Represents the impact from measurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017.
(6) Represents the amount of accelerated depreciation derived from the repowering of wind farms in Renewables.
(7) Represents costs incurred in connection with the COVID-19 pandemic.
(8) Pre-merger costs incurred.
(9) Removal of the impact from Gas activity in the reconciliation to AVANGRID Net Income.
(10) Adjusted Net Income and Adjusted Earnings Per Share are non-GAAP financial measures and are presented after excluding restructuring charges, loss from held for sale measurement, impact of the Tax Act, accelerated depreciation derived from the repowering wind farms, MtM activities in Renewables, costs incurred related to the PNMR Merger, costs incurred in connection with the COVID-19 pandemic, merger costs and the Gas storage businesses.

Liquidity and Capital Resources

Our operations, capital investment and business development require significant short-term liquidity and long-term capital resources. Historically, we have used cash from operations, and borrowings under our credit facilities and commercial paper program as our primary sources of liquidity. Our long-term capital requirements have been met primarily through retention of earnings and borrowings in the investment grade debt capital markets. Continued access to these sources of liquidity and capital are critical to us. Risks may increase due to circumstances beyond our control, such as a general disruption of the financial markets and adverse economic conditions.

Liquidity

We manage our overall liquidity position as part of the group of companies controlled by Iberdrola, or the Iberdrola Group, and are a party to a liquidity agreement with Bank of America, N.A. along with certain members of the Iberdrola Group. The liquidity agreement aids the Iberdrola Group in efficient cash management and reduces the need for external borrowing by the pool participants. Parties to the agreement, including us, may deposit funds with or borrow from the financial institution, provided that the net balance of funds deposited or borrowed by all pool participants in the aggregate is not less than zero. As of December 31, 2020 and 2019, the balance was $0 and $150 million, respectively. Any deposit amounts would be reflected in our consolidated balance sheets under cash and cash equivalents because our deposited surplus funds under the cash pooling agreement are highly-liquid short-term investments.

We optimize our liquidity within the United States through a series of arms-length intercompany lending arrangements with our subsidiaries and among our regulated utilities to provide for lending of surplus cash to subsidiaries with liquidity needs, subject to the limitation that the regulated utilities may not lend to unregulated affiliates. At December 31, 2020, we had cash and cash equivalents of $1,463 million, as compared to $178 million at December 31, 2019. In addition to cash on hand, we have the capacity to borrow up to $2.5 billion from the lenders committed to the AVANGRID Credit Facility, $500 million from the lenders committed to the 2020 Credit Facility and $500 million from an Iberdrola Group Credit Facility, each of which are described below.

AVANGRID Commercial Paper Program

AVANGRID has a commercial paper program with a limit of $2 billion that is backstopped by the AVANGRID Credit Facility (described below). As of December 31, 2020 and February 26, 2021, there was $309 million and $0 of commercial paper outstanding, respectively.

AVANGRID Credit Facility

AVANGRID and its subsidiaries, NYSEG, RG&E, CMP, UI, CNG, SCG and BGC, each of which are joint borrowers, have a revolving credit facility with a syndicate of banks, or the AVANGRID Credit Facility, that provides for maximum borrowings of up to $2.5 billion in the aggregate.

Under the terms of the AVANGRID Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. On June 29, 2020, we entered into an amendment to the AVANGRID Credit Facility, which reduced AVANGRID's maximum sublimit from $2.0 billion to $1.5 billion and added minimum sublimits for each joint borrower other than AVANGRID. Under the AVANGRID Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. As of December 31, 2020, the facility fees ranged from 10.0 to 17.5 basis points. The AVANGRID Credit Facility matures on June 29, 2024. As of both December 31, 2020 and February 26, 2021, we had no borrowings outstanding under this credit facility.

2020 Credit Facility

On June 29, 2020, we entered into a revolving credit agreement with several lenders, or the 2020 Credit Facility, that provides maximum borrowings up to $500 million. We are required to pay an annual facility fee, which ranges from 15 to 30 basis points, dependent on AVANGRID’s credit rating. As of December 31, 2020, the facility fee is 20 basis points. The 2020 Credit Facility matures on June 28, 2021. We have the right to extend, and the banks are obligated to extend, the commitments and loans outstanding under the facility for one year at a cost of 75 basis points. We may also request an extension of the facility for one year, which the banks may grant at their discretion for a fee that will be determined at the time of the request. As of both December 31, 2020 and February 26, 2021, we had no borrowings outstanding under this credit facility.

Since our credit facilities are also a backstop to the AVANGRID commercial paper program, the total amounts available under the facilities as of December 31, 2020 and February 26, 2021, were $2,691 million and $3,000 million, respectively.

Iberdrola Group Credit Facility

AVANGRID has a credit facility with Iberdrola Financiacion, S.A.U., a company of the Iberdrola Group. The facility has a limit of $500 million and matures on June 18, 2023. AVANGRID pays a facility fee of 10.5 basis points annually. As of both December 31, 2020 and February 26, 2021, there was no outstanding amount under this credit facility.

Long-Term Capital Resources

We expect to meet our long-term capital requirements through the use of our cash balances, credit facilities, cash from operations and long-term borrowings. We have investment grade ratings from Standard and Poor’s, Moody’s and Fitch and we believe that we can raise capital on competitive terms in the investment grade debt capital and/or bank markets.

Iberdrola Loan

On December 14, 2020, AVANGRID and Iberdrola entered into an intra-group loan agreement which provided AVANGRID with an unsecured subordinated loan in an aggregate principal amount of $3,000 million (the Iberdrola Loan).

The Iberdrola Loan bears interest (i) from December 16, 2020 until June 15, 2021, at an interest rate of 0.20%, which increases one basis point each month following the first month of the term of the Iberdrola Loan up to a maximum interest rate of 0.25%, and (ii) from June 16, 2021 until the Iberdrola Loan and any accrued and unpaid interest is repaid in its entirety, at AVANGRID’s equity cost of capital as published by Bloomberg. Interest is payable on a monthly basis in arrears.

AVANGRID is required to repay the Iberdrola Loan in full upon certain equity issuances by AVANGRID in which Iberdrola participates or a change of control of AVANGRID. In addition, on or after June 15, 2021, upon five business days' notice to Iberdrola, AVANGRID may voluntarily repay the Iberdrola Loan and any accrued and unpaid interest, in whole or in part, without prepayment premium or penalty if there is a change in AVANGRID's business plan and AVANGRID determines that the Iberdrola Loan is no longer required. The intra-group loan agreement contains certain customary affirmative and negative covenants and events of default.

Our other long-term debt issuances during 2020 were as follows:

Company	Issue Date	Type	Amount (Millions)	Interest rate	Maturity
AVANGRID	4/9/2020	Unsecured Notes	$ 750	3.20 %	2025
NYSEG (1)	5/1/2020	Pollution Control Bonds	$ 200	1.40% - 1.61%	2026 -2029
BGC	9/1/2020	Unsecured Notes	$ 25	3.68 %	2050
NYSEG	9/25/2020	Unsecured Notes	$ 200	1.95 %	2030
RG&E	11/23/2020	First Mortgage Bonds	$ 200	1.85 %	2030
UI	12/1/2020	Unsecured Notes	$ 75	2.02 %	2030
CMP	12/15/2020	First Mortgage Bonds	$ 50	1.87 %	2030
CNG	12/15/2020	Unsecured Notes	$ 30	2.02 %	2030
SCG	12/15/2020	First Mortgage Bonds	$ 50	1.87 %	2030

At December 31, 2020, Networks had $5,706 million of debt, including the current portion thereof, consisting of first mortgage bonds, senior unsecured notes, tax-exempt bonds and various other forms of debt. Networks' regulated utilities are required by regulatory order to maintain a minimum ratio of common equity to total capital that is tied to the capital structure used in the establishment of their revenue requirements. Pursuant to these requirements, each of NYSEG, RG&E, CMP and MNG must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, each utility must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. UI, SCG, CNG and BGC are restricted from paying dividends if paying such dividend would result in their respective common equity ratio being lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. The regulated utilities periodically pay dividends to, or receive capital contributions from, AVANGRID in order to maintain the minimum equity ratio requirement. They each independently incur indebtedness by issuing investment grade debt securities. Networks' regulated utilities were in compliance with these regulatory orders as of December 31, 2020.

At December 31, 2020, we had a $47 million finance lease liability outstanding in the Renewables segment relating to a sale-leaseback arrangement on a solar generation facility. Renewables has also sourced capital through tax equity financing arrangements associated with certain wind farm projects. The arrangements allocate substantially all of the projects' taxable income and PTCs to the tax equity investor, along with a small percentage of cash generated by the projects, in exchange for an initial contribution. During 2020, Renewables closed on the sale of a tax equity interest in its Aeolus Wind Power VII, LLC portfolio, which resulted in proceeds of $307 million.

At December 31, 2020, corporate had $2,085 million of long-term debt, including the current portion thereof, outstanding not including the Iberdrola Loan. Long-term debt in corporate consists mainly of $600 million of 3.15% notes due in 2024, $750 million of 3.20% notes due in 2025 and $750 million of 3.80% notes due in 2029.

In our credit facilities, long-term borrowings, financing leases and tax-equity partnerships, we and our affiliates that are parties to the agreements are subject to covenants that are standard for such agreements. Affirmative covenants impose certain obligations on the borrower and negative covenants limit certain activities by the borrower. The agreements also define certain events of default, including but not limited to non-compliance with the covenants that may automatically in some circumstances, or at the option of the lenders in other circumstances, trigger acceleration of the obligations. We and our affiliates were in compliance with all such covenants at December 31, 2020.

Capital Requirements

Funding Future Common Dividend Payments

We expect to fund any quarterly shareholder dividends primarily from the cash provided by operations of our businesses in the future. We have revolving credit facilities and a commercial paper program, as described above, to fund short-term liquidity needs and we believe that we will have access to the capital markets should additional, long-term growth capital be necessary.

Capital Expenditures

The regulated utilities' capital expenditures over the last three years have been as follows:

	2020	2019	2018
		(in millions)	
NYSEG	$ 689	$ 574	$ 517
RG&E	387	379	283
CMP	389	299	212
MNG	3	7	7
UI	204	192	153
SCG	88	83	57
CNG	60	60	55
BGC	17	19	17
Total	**$ 1,837**	**$ 1,613**	**$ 1,301**

Networks increased its capital expenditures during the period from 2018 to 2020 to upgrade and expand electricity and natural gas transmission and distribution infrastructure. In 2020, NYSEG and RG&E continued their capital investments in a number of programs, including the grid automation project, distribution line project, FERC compliance programs, Rochester Area Reliability Project, or RARP, and Gas Distribution Mains and Leak Prone Main replacement project. In 2019, CMP's projects were mainly the NECEC Project, Spectrum Energy Management System Project, Fleet Services, Physical and Cyber Security, Line Inspection and Waterville-Winslow Reliability Project. UIL's projects were mainly driven by new customer connections, system and corrective reliability, system resiliency, infrastructure replacement and system operations.

Renewables' capital expenditures for the years set forth below were as follows:

	2020	2019	2018
		(in millions)	
Wind & solar	$ 822	$ 1,281	$ 277
Thermal	8	7	25
Corporate (1)	15	13	13
Total capital expenditures	**$ 845**	**$ 1,301**	**$ 315**

(1) Includes information technology and facilities and safety (security).

In 2020, Renewables made capital expenditures of $822 million on construction of La Joya, Tatanka Ridge, Roaring Brook, Golden Hills and other wind and solar assets and $8 million in capital expenditures on the Klamath gas-fired cogeneration facility, or the Klamath Plant.

In 2019, Renewables made capital expenditures of $1.2 billion on construction of Otter Creek, Karankawa, Montague, Tatanka Ridge and other wind and solar assets as well as the acquisition of Patriot Wind, $7 million in capital expenditures on the Klamath Plant, $15 million on improvements to operating wind assets and $31 million in development costs.

In 2018, Renewables made capital expenditures of $232 million on construction of Otter Creek, Karankawa, Montague, Wy'East Solar and other wind and solar assets, $25 million in capital expenditures on the Klamath Plant, $17 million on improvements to operating wind assets and $28 million in development costs.

Capital Projects

An important part of our business strategy involves capital projects. Networks plans to invest a total of approximately $9.6 billion from 2021 to 2025 to upgrade and expand electricity and natural gas transmission and distribution infrastructure. In the next 12 months, Networks plans to invest $704 million in Maine, including $500 million for NECEC, substation modernization, Distribution Line inspection and betterments, CMP Automation, Line Inspection and Spring Street Substation. In addition, CMP plans to continue developing its new customer relationship management and billing system and new transmission investments in MEPCO, 388 rebuild. MEPCO plans to invest $32 million in the next 12 months. NYSEG plans to invest $706 million in the next 12 months, including: NYSEG AMI Hardware/Software Project, BES Program – Binghamton Area Brightline, NYSEG Distribution Line Project, Vehicle Purchases, NWA- Java Substation, Gas Distribution Mains and Leak Prone Main replacement. RG&E plans to invest $382 million in the next 12 months, including: RGE AMI Hardware/

Software Project, RARP, BES Program - Retail, Circuit 794 Rebuild, Pole replace (WPIT) Program, Gas Distribution Mains and Leak Prone Main replacement programs. UIL plans to invest $353 million in the next 12 months, including a number of programs and projects related to betterments, new customer connections, replacement of aging infrastructure, and improvement of system operations, reliability and resiliency. For gas operations, the most notable investments include distribution main replacements, leak prone replacement, gas meters, infrastructure expansion and the connection of new customers.

Renewables plans to invest at least a total of approximately $8.2 billion from 2021 to 2025 and add at least approximately 6,200 MW of generation capacity.

We expect to fund these capital projects through a combination of cash provided by operations and access to the capital markets, including debt borrowings at either the subsidiary or holding company level and equity issuances as needed. Additionally, we have revolving credit facilities, as described above, to fund short-term liquidity needs.

Cash Flows

Our cash flows depend on many factors, including general economic conditions, regulatory decisions, weather, commodity price movements and operating expense and capital spending control.

The following is a summary of the cash flows by activity for the years ended December 31, 2020, 2019 and 2018, respectively:

	Year Ended December 31,		
	2020	**2019**	**2018**
	(in millions)		
Cash Flows			
Net cash provided by operating activities	$ 1,288	$ 1,588	$ 1,781
Net cash used in investing activities	(2,858)	(2,708)	(1,554)
Net cash provided by (used in) from financing activities	2,853	1,261	(230)
Net increase (decrease) in cash, cash equivalents and restricted cash	**$ 1,283**	**$ 141**	**$ (3)**

Operating Activities

Our primary sources of operating cash inflows are proceeds from transmission and distribution of electricity and natural gas and sales of wholesale energy and energy related products and services. Our primary operating cash outflows are power and natural gas purchases and transmission operating and maintenance expenses, as well as personnel costs and other employee-related expenditures. As our business has expanded, our working capital requirements have grown. We expect our working capital to grow as we continue to grow our business.

The cash from operating activities for the year ended December 31, 2020 compared to the year ended December 31, 2019 decreased by $300 million, primarily attributable to higher operations and maintenance expenses including from storm and other activities, delays in the timing of the approval of the 2020 Joint Proposal and increased overdue receivables as a result of COVID-19 in Networks.

The cash from operating activities for the year ended December 31, 2019 compared to the year ended December 31, 2018 decreased by $193 million, primarily attributable to higher operations and maintenance expenses and cash interest paid in the period.

The cash from operating activities for the year ended December 31, 2018 compared to the year ended December 31, 2017 increased by $18 million, primarily attributable to increased operating revenues in the period.

Investing Activities

Our investing activities have primarily focused on enhancing, automating and reinforcing our asset base to support safety, reliability and customer growth in accordance with the regulatory markets within which we operate, as well as constructing solar and wind assets and spending on gas generation assets.

In 2020, net cash used in investing activities was $2,858 million, which was comprised of $2,781 million of capital expenditures and $370 million of other investments and equity method investments, partially offset by $48 million of contributions in aid of construction and $238 million of proceeds from the sale of assets.

In 2019, net cash used in investing activities was $2,708 million, which was comprised of $2,735 million of capital expenditures and $176 million of other investments and equity method investments, partially offset by $74 million of contributions in aid of construction and $126 million of proceeds from the sale of assets.

In 2018, net cash used in investing activities was $1,554 million, which was comprised of $1,777 million of capital expenditures, partially offset by $60 million of contributions in aid of construction, $4 million of cash distributions from equity method investments, and proceeds from sale of assets of $204 million primarily related to the sale of assets held for sale.

Financing Activities

Our financing activities have primarily consisted of using our credit facilities and long-term debt issued or redeemed by AVANGRID and our regulated Networks subsidiaries.

In 2020, financing activities provided $2,853 million in cash reflecting primarily an issuance of non-current debt at AVANGRID and our regulated subsidiaries with the net proceeds of $1,367 million, receipt of the Iberdrola Loan of $3,000 million and tax equity financing contributions from non-controlling interests of $312 million, offset by a net decrease in non-current debt and current notes payable of $1,264 million, distributions to non-controlling interests of $5 million, payments on capital leases of $9 million and dividends of $545 million.

In 2019, financing activities provided $1,261 million in cash reflecting primarily an issuance of non-current debt at AVANGRID and our regulated subsidiaries with the net proceeds of $2,137 million and tax equity financing contributions from non-controlling interests of $133 million, offset by a net decrease in non-current debt and current notes payable of $374 million, distributions to non-controlling interests of $63 million, payments on capital leases of $27 million and dividends of $545 million.

In 2018, financing activities used $230 million in cash reflecting primarily an issuance of non-current debt at NYSEG, RG&E, CMP and UI with the net proceeds of $597 million, tax equity financing contributions from non-controlling interests of $223 million, offset by a net decrease in non-current debt and current notes payable of $418 million, distributions to non-controlling interests of $76 million, payments on capital leases of $13 million and dividends of $537 million.

Contractual Obligations

As of December 31, 2020, our contractual obligations (excluding any tax reserves) were as follows:

	Total	2021	2022	2023	2024	2025	Thereafter
				(in millions)			
Leases (1)	$ 513	$ 25	$ 20	$ 66	$ 33	$ 12	$ 357
Easements (2)	1,012	28	28	26	28	29	873
Projected future pension benefit plan contributions (3)	400	92	105	93	60	50	—
Long-term debt (including current maturities) (4)	10,791	313	363	439	612	1,107	7,957
Interest payments (5)	3,018	297	288	267	256	215	1,695
Material purchase commitments (6)	1,113	861	107	48	20	16	61
Total Contractual Obligations	**$ 16,847**	**$ 1,616**	**$ 911**	**$ 939**	**$ 1,009**	**$ 1,429**	**$ 10,943**

(1) Represents lease contracts relating to operational facilities, office building leases and vehicle and equipment leases. These amounts represent our expected unadjusted portion of the costs to pay as amounts related to contingent payments are predominantly linked to electricity generation at the respective facilities.
(2) Represents easement contracts which are not classified as leases.
(3) The qualified pension plans' contributions are generally based on the estimated minimum pension contributions required under the Employee Retirement Income Sensitivity Act of 1974, as amended, and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status and agreements with state regulatory agencies. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2025 are not included as projections beyond 2025 are not available.
(4) Includes the Iberdrola Loan. See debt payment discussion in "Long-term Capital Resources."
(5) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2020, and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2020.
(6) Represents forward purchase commitments under power, gas and other arrangements and contractual obligations for material and services on order but not yet delivered at December 31, 2020.

Critical Accounting Policies and Estimates

We have prepared the financial statements provided herein in accordance with U.S. GAAP and they include the accounts of AVANGRID and its consolidated subsidiaries. We describe our significant accounting policies in Note 3 to the consolidated financial statements.

In preparing the accompanying financial statements, our management has made certain estimates and assumptions that affect the reported amounts of assets, liabilities, shareholder's equity, revenues and expenses and the disclosures thereof. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and that require the use of estimates, assumptions and judgments to determine matters that are inherently uncertain.

Accounting for Regulated Public Utilities

U.S. GAAP allows regulated entities to give accounting recognition to the actions of regulatory authorities. We must meet certain criteria in order to apply such regulatory accounting treatment and record regulatory assets and liabilities. In determining whether we meet the criteria for our operations, our management makes significant judgments, which involve (i) determining whether rates for services provided to customers are subject to approval by an independent, third-party regulator, (ii) determining whether the regulated rates are designed to recover specific costs of providing the regulated service, (iii) considering relevant historical precedents and recent decisions of the regulatory authorities and (iv) considering the fact that decisions made by regulatory commissions or legislative changes at a later date could vary from earlier interpretations made by management and that the impact of such variations could be material. Our regulated subsidiaries have deferred recognition of costs (a regulatory asset) or have recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations relieved in the future through the ratemaking process. Management regularly reviews our regulatory assets and liabilities to determine we need to make whether adjustments to our previous conclusions based on the current regulatory environment as well as recent rate orders. If our regulated subsidiaries, or a portion of their assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for unregulated businesses in general would become applicable and immediate recognition of any previously deferred costs would be required in the year in which such criteria are no longer met.

Accounting for Pensions and Other Post-Retirement Benefits

We provide pensions and other post-retirement benefits for a significant number of employees, former employees and retirees. We account for those benefits in accordance with the accounting rules for retirement benefits. In accounting for our pension and other post-retirement benefit plans, or the AVANGRID plans, we make assumptions regarding the valuation of benefit obligations and the performance of plan assets. The primary assumptions include the discount rate, the expected long-term return on plan assets, health care cost trend rates, mortality assumptions, demographic assumptions and other factors. We apply consistent estimation techniques regarding our actuarial assumptions, where appropriate, across the AVANGRID plans of our operating subsidiaries. The estimation technique we use to develop the discount rate for the AVANGRID plans is based upon the settlement of such liabilities as of December 31, 2020, using a hypothetical portfolio of actual, high quality bonds, that would generate cash flows required to settle the liabilities. We believe such an estimate of the discount rate accurately reflects the settlement value for plan obligations and results in cash flows that closely match the expected payments to participants. The estimation technique we use to develop the long-term rate of return on plan assets is based on a projection of the long-term rates of return on plan assets that will be earned over the life of the plan, including considerations of investment strategy, historical experience and expectations for long-term rates of return.

We reflect unrecognized prior service costs and credits and unrecognized actuarial gains and losses for the regulated utilities of Networks as regulatory assets or liabilities if it is probable that such items will be recovered through the ratemaking process in future periods. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in Accumulated Other Comprehensive Loss.

Business Combinations and Assets Acquisitions

We apply the acquisition method of accounting to account for business combinations. The consideration transferred for an acquisition is the fair value of the assets transferred, the liabilities incurred, including contingent consideration, and the equity interests issued by the acquirer. We measure identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination initially at their fair values at the acquisition date. We record as goodwill the excess of the consideration transferred over the fair value of the identifiable net assets acquired. We recognize adjustments to provisional amounts relating to a business combination that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. For business combinations, we expense acquisition-related costs as incurred.

In contrast to a business combination (disposal), we classify a transaction as an asset acquisition (disposal) when substantially all the fair value of the gross assets acquired (disposed) is concentrated in a single identifiable asset or group of similar identifiable assets or otherwise does not meet the definition of a business. For asset acquisitions, we capitalize acquisition-related costs as a component of the cost of the assets acquired and liabilities assumed.

Goodwill

Goodwill is not amortized, but is subject to an assessment for impairment performed in the fourth quarter or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of a reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which we test goodwill for impairment.

In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our reporting units, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity specific events, and events affecting a reporting unit.

Our quantitative impairment testing includes various assumptions, primarily the discount rate, and forecasted cash flows. We use a discount rate that is developed using market participant assumptions, which consider the risk and nature of the respective reporting unit's cash flows and the rates of return market participants would require in order to invest their capital in our reporting units. We test the reasonableness of the conclusions of our quantitative impairment testing using a range of discount rates and a range of assumptions for long-term cash flows.

Impairment of Long-Lived Assets

We evaluate property, plant and equipment and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. If indicators of impairment are present, a recoverability test is performed based on undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. An impairment loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset. The impairment loss to be recognized is the amount by which the carrying value of the long-lived asset exceeds the asset's fair value.

We determine the fair value of a long-lived asset by applying the income approach prescribed under the fair value measurement accounting framework. We develop the underlying assumptions consistent with a market participant's view of the exit price of our assets. We use an internal discounted cash flow, or DCF, valuation model based on the principles of present value techniques to estimate the fair value of our long-lived assets under the income approach. The DCF model estimates fair value by discounting AVANGRID's cash flow forecasts at an appropriate market discount rate. Management applies a considerable amount of judgment in the estimation of the discount rate used in the DCF model and in selecting several input assumptions during the development of our cash flow forecasts. Examples of the input assumptions that our forecasts are sensitive to include macroeconomic factors such as growth rates, industry demand, inflation, power prices and commodity prices. Many of these input assumptions are dependent on other economic assumptions, which are often derived from statistical economic models with inherent limitations such as estimation differences. Further, several input assumptions are based on historical trends which often do not recur. The input assumptions that include significant unobservable inputs most significant to our cash flows are based on expectations of macroeconomic factors, which may be volatile. The use of a different set of input assumptions could produce significantly different cash flow forecasts.

The fair value of a long-lived asset is sensitive to both input assumptions related to our cash flow forecasts and the market discount rate. Further, estimates of long-term growth and terminal value are often critical to the fair value determination. As part of the impairment evaluation process, management analyzes the sensitivity of fair value to various underlying assumptions. The level of scrutiny increases as the gap between fair value and carrying amount decreases. Changes in any of these assumptions could result in management reaching a different conclusion regarding the potential impairment, which could be material. Our impairment evaluations inherently involve uncertainties from uncontrollable events that could positively or negatively impact the anticipated future economic and operating conditions.

Income Taxes

AVANGRID files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences based on enacted tax laws of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, certain of our regulated subsidiaries have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer the ITCs when earned and amortize them over the estimated lives of the related assets.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. Changes in deferred income tax assets and liabilities that are associated with components of other comprehensive income, or OCI, are charged or credited directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within "Interest expense, net of capitalization" and "Other income and (expense)" of the consolidated statements of income.

Uncertain tax positions have been classified as noncurrent unless expected to be paid within one year. In 2019, we netted our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

Federal PTCs applicable to our renewable energy facilities, that are not part of a tax equity financing arrangement, are recognized as a reduction in income tax expense with a corresponding reduction in deferred income tax liabilities due to our inability to immediately monetize the tax credits.

Our income tax expense, deferred tax assets and liabilities and liabilities for unrecognized tax benefits reflect management's best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

Off-Balance Sheet Arrangements

At December 31, 2020, we had approximately $3,989 million of standby letters of credit, surety bonds, guarantees and indemnifications outstanding, which includes guarantees of our own performance. These instruments provide financial assurance to the business and trading partners of AVANGRID and its subsidiaries in their normal course of business. The instruments only represent liabilities if AVANGRID or its subsidiaries fail to deliver on contractual obligations. We therefore believe it is unlikely that any material liabilities associated with these instruments will be incurred and, accordingly, as of December 31, 2020, neither we nor our subsidiaries have any liabilities recorded for these instruments.

New Accounting Standards

For discussion of new accounting pronouncements that affect AVANGRID, refer to Note 3 to our consolidated financial statements contained in this Annual Report on Form 10-K.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk.***

We are exposed to risks associated with adverse changes in commodity prices, interest rates and equity prices. Financial instruments and positions affecting our financial statements described below are held primarily for purposes other than trading. Market risk is measured as the potential loss in fair value resulting from hypothetical reasonably possible changes in commodity prices, interest rates or equity prices over the next year. Management has established risk management policies to monitor and manage such market risks, as well as credit risks.

Commodity Price Risk

Renewables faces a number of energy market risk exposures, including fixed price, basis (both location and time) and heat rate risk.

Long-term supply contracts reduce our exposure to market fluctuations. We have electricity commodity purchases and sales contracts for energy (physical contracts) that have been designated and qualify for the normal purchase normal sale exemption in accordance with the accounting requirements concerning derivative instruments and hedging activities.

Renewables merchant wind facilities are subject to price risk, which is hedged with fixed price power trades. Its combined cycle power plant is subject to heat rate risk, which is hedged with fixed price power and fixed price gas and basis positions. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Some long-term hedges do not qualify for hedge accounting. This introduces some MtM volatility into yearly profit and loss accounts.

Renewables uses a Monte Carlo simulation value-at-risk, or VaR, technique to measure and control the level of risk it undertakes. VaR is a statistical technique used to measure and quantify the level of risk within a portfolio over a given timeframe and within a specified level of confidence. VaR is primarily composed of three variables: the measured amount of potential loss, the probability of not exceeding the amount of potential loss and the portfolio holding period.

Renewables uses a 99% probability level over a five-day holding period, indicating that it can be 99% confident that losses over five days would not exceed that value. The average VaR for 2020 was $23.9 million compared to a 2019 average of $20.6 million.

As noted above, VaR is a statistical technique and is not intended to be a guarantee of the maximum loss Renewables may incur.

Networks also experiences commodity price risk, due to volatility in the wholesale energy markets. Networks manages that risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Networks also uses electricity contracts as deemed appropriate, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. It also uses natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. It includes the cost or benefit of those contracts in the amount expensed for electricity or natural gas purchased when the related electricity is sold.

Because all gains or losses on Networks' commodity contracts will ultimately be passed on to retail customers, no sensitivity analysis is performed for Networks. Further information regarding the derivative financial instruments and sensitivity analysis is provided in Notes 11 and 12 of our consolidated financial statements contained in this Annual Report on Form 10-K.

Interest Rate Risk

Total debt outstanding, including commercial paper of $309 million, was $11,100 million at December 31, 2020, of which $309 million had a floating interest rate; a change of 25 basis points in this interest rate would result in an interest expense fluctuation of approximately $1 million annually. The estimated fair value of our long-term debt at December 31, 2020 was $12,166 million, in comparison to a book value of $10,791 million.

AVANGRID uses financial derivative instruments from time to time to alter its fixed and floating rate debt balances or to hedge fixed rates in anticipation of future fixed rate issuances. Further information regarding our interest rate derivative financial instruments is provided in Note 12 of our consolidated financial statements contained in this Annual Report on Form 10-K. There were no interest rate derivative contracts outstanding at December 31, 2020.

Pension and Other Post-Retirement Plans

We provide pensions and other post-retirement benefits for a significant number of employees, former employees and retirees. In applying relevant accounting policies, we have made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, discount rates, health care cost trends and future compensation. The cost of pension and other post-retirement benefits in future periods will depend on actual returns on plan assets, assumptions for future periods, contributions and benefit experience. In 2020, we contributed $102 million to our pension and other post-retirement plans. Our contribution to our pension and other post-retirement plans in 2021 is expected to be approximately $92 million.

The weighted-average discount rates used in accounting for qualified pension obligations in 2020 was 2.34%. The expected rate of return on plan assets for qualified pension benefits in 2020 was 7.30%. The following tables reflect the estimated sensitivity associated with a change in certain significant actuarial assumptions (each assumption change is presented mutually exclusive of other assumption changes):

		Impact on 2020 Pension Expense Increase (Decrease)	
	Change in Assumption	**Pension Benefits**	**Post Retirement Benefits**
		(in millions)	
Increase in discount rate	50 basis points	$ (18)	$ (2)
Decrease in discount rate	50 basis points	$ 18	$ 2
Increase in return on plan assets	50 basis points	$ (14)	$ (1)
Decrease in return on plan assets	50 basis points	$ 14	$ 1

Credit Risk

This risk is defined as the risk that a third party will not fulfill its contractual obligations and, therefore, generate losses for AVANGRID. Networks is exposed to nonpayment of customer bills. Standard debt recovery procedures are in place, in accordance with best practices and in compliance with applicable state regulations and embedded tariff mechanisms to manage uncollectable expense. Our credit department, based on guidelines approved by our board, establishes and manages its counterparty credit limits. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating. Credit risk is mitigated by contracting with multiple counterparties and limiting exposure to individual counterparties or counterparty families to clearly defined limits based upon the risk of counterparty default. At the counterparty level, we employ specific eligibility criteria in determining appropriate limits for each prospective counterparty and supplement this with netting and collateral agreements, including margining, guarantees, letters of credit and cash deposits, where appropriate.

Renewables is also exposed to credit risk through its energy management operations. Counterparty credit risk is managed through established credit policies by a credit department that is independent of the energy management function. Prospective and existing customers are reviewed for creditworthiness based upon established criteria. Credit limits are set in accordance with board approved guidelines, with counterparties not meeting minimum standards providing various credit enhancements such as cash prepayments, letters of credit, cash and other collateral and guarantees. Master netting agreements are used, where appropriate, to offset cash and non-cash gains and losses arising from derivative instruments with the same counterparty. Trade receivables and other financial instruments are predominately with energy, utility and financial services-related companies, as well as municipalities, cooperatives and other trading companies in the U.S., although there is a growing segment of long-term power sales (PPAs) signed with commercial and industrial customers of high credit quality.

Based on our policies and risk exposures related to credit risk from its management in Renewables, we do not anticipate a material adverse effect on our financial statements as a result of counterparty nonperformance. As of December 31, 2020, approximately 98% of our energy management counterparty credit risk exposure is associated with companies that have investment grade credit ratings.

Treasury Management (including Liquidity Risk)

We manage our overall liquidity position as part of the group of companies controlled by the Iberdrola Group, and are a party to a liquidity agreement with a financial institution, along with certain members of the Iberdrola Group. We optimize our liquidity within the United States through a series of arms-length intercompany lending arrangements with our subsidiaries and among the regulated utilities to provide for lending of surplus cash to subsidiaries with liquidity needs, subject to the limitation that the regulated utilities may not lend to unregulated affiliates. These arrangements minimize overall short-term funding costs and maximize returns on the temporary cash investments of the subsidiaries. We also have a bi-lateral demand note agreement with a Canadian affiliate of the Iberdrola Group. We have the capacity to borrow from third parties through a $2 billion commercial paper program, the $2.5 billion AVANGRID Credit Facility and $500 million 2020 Credit Facility, both of which backstop the commercial paper program, and $500 million from an Iberdrola Group Credit Facility. For more information, see the section entitled "—Liquidity and Capital Resources—Liquidity Resources" of this Annual Report on Form 10-K.

Networks

Networks' regulated utilities fund their operations independently, except to the extent that they borrow on a short-term basis from unregulated affiliates and from each other when circumstances warrant in order to minimize short-term funding costs and maximize returns on temporary cash investments. The regulated utilities are prohibited by regulatory order from lending to unregulated affiliates. Networks' regulated utilities each independently accesses the investment grade debt capital markets for long-term funding and each are borrowers under the AVANGRID Credit Facility described in "—Liquidity and Capital Resources—Liquidity Resources" of this Annual Report on Form 10-K.

Networks' regulated utilities are subjected by regulatory order to certain credit quality maintenance measures, including minimum equity ratios, that are linked to the level of equity assumed in the establishment of revenue requirements. The companies maintain their equity ratios at or above the minimum through dividend declarations or, when necessary, capital contributions from AVANGRID.

Renewables

Renewables historically has been financed through equity contributions, intercompany loans during construction, tax equity partnerships and, to a lesser extent, sale-leaseback arrangements. The outstanding balance of its financing lease was $47 million at December 31, 2020.

Renewables is a party to a cash pooling arrangement with Avangrid, Inc. All Renewables revenues are concentrated in and all Renewables disbursements are made from Avangrid, Inc. Net cash surpluses or deficits at Renewables are recorded as intercompany receivables or payables and these balances are periodically reduced to zero through dividends or capital contributions. In March 2020, Renewables recorded a net non-cash dividend of $1,668 million to Avangrid, Inc. to zero out account balances that had principally accumulated prior to January 2020.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Avangrid, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Avangrid, Inc. and subsidiaries (the Company) as of December 31, 2020 and 2019, the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes and financial statement schedule I (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 1, 2021 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Evaluation of the impairment of the carrying value of goodwill in the Renewables reporting unit

As discussed in Notes 3(g) and 7 to the consolidated financial statements, the goodwill balance as of December 31, 2020 was $3,119 million, of which $372 million related to the Renewables reporting unit. The Company performs goodwill impairment testing on an annual basis or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

We identified the evaluation of the impairment of the carrying value of goodwill in the Renewables reporting unit as a critical audit matter due to certain estimates and assumptions the Company made to determine the fair value of the Renewables reporting unit. As a result, a higher degree of auditor judgment was required to evaluate certain assumptions used in the Company's estimate of the fair value of the Renewables reporting unit. Specifically, the Company's determination of the forecasted power production and forecasted market prices, which are used to develop the revenue forecast, and the determination of the discount rates, required subjective and challenging auditor judgment.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's goodwill impairment assessment process, including controls related to the determination of the forecasted power production, forecasted market prices and discount rates used to estimate the fair value of the Renewables reporting unit. To assess the Company's ability to forecast revenues, we compared the Renewables reporting unit's historical revenue forecasts to actual revenues. We compared the Renewables reporting unit's forecasted power production to historical power production. We also evaluated the forecasted market prices by comparing them to third-party published reports by industry analysts. In addition, we involved valuation professionals with specialized skills and knowledge, who assisted in testing the selected discount rates by independently developing discount rates using publicly available market data for comparable entities and comparing them to the Company's discount rates.

Evaluation of regulatory assets and liabilities

As discussed in Notes 3(c) and 6 to the consolidated financial statements, the Company accounts for their regulated operations in accordance with Financial Accounting Standards Board Accounting Standard Codification Topic 980, Regulated Operations (ASC Topic 980). Pursuant to the requirements of ASC Topic 980, the financial statements of a rate-regulated enterprise reflect the actions of regulators. The Company capitalizes, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. In addition, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs are recorded as regulatory liabilities. The Company's regulated utilities are subject to complex and comprehensive federal, state and local regulation and legislation, including regulations promulgated by state utility commissions and the Federal Energy Regulatory Commission.

We have identified the evaluation of regulatory assets and liabilities as a critical audit matter. This was due to the extent of audit effort required in the evaluation of regulatory assets and liabilities in each of the relevant jurisdictions.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's regulatory accounting process, including controls related to the Company's application of ASC Topic 980 in each jurisdiction and the Company's calculation and review of regulatory assets and liabilities. We selected regulatory assets and liabilities and assessed the Company's application of ASC Topic 980 in the relevant jurisdiction by evaluating the underlying orders, statutes, rulings, memorandums, filings or publications issued by the respective regulators. We selected a sample of the regulatory assets and liabilities activity and using the methodologies approved by the relevant regulatory commissions, recalculated the activity and agreed the data used in the calculations to the Company's underlying books and records. We compared the amounts calculated by the Company to the amounts recorded in the consolidated financial statements.

Evaluation of tax equity financing arrangements

As discussed in Notes 3(e), 3(p) and 20 to the consolidated financial statements, the Company participates in certain tax equity financing arrangements (TEFs) that qualify as variable interest entities (VIEs). For TEFs where the economic allocations of income are not based on pro rata ownership percentages, a balance sheet-oriented hypothetical liquidation at book value (HLBV) method is used to reflect the substantive profit sharing arrangement. Under the HLBV method, the amounts reported as noncontrolling interests and net income (loss) attributable to noncontrolling interests in the consolidated balance sheets and consolidated statements of income represent the amounts the noncontrolling interest would hypothetically receive at each balance sheet date under the liquidation provisions of each partnership's ownership agreement assuming the net assets of the projects were liquidated at recorded amounts and distributed to the equity holders. Noncontrolling interests and net loss attributable to noncontrolling interests as of and for the year ended December 31, 2020 were $617 and $42 million, respectively.

We identified the evaluation of tax equity financing arrangements as a critical audit matter. This was due to the nature and extent of audit effort required to evaluate the HLBV methodology, which included specialized skills and knowledge to evaluate that the HLBV methodology used was consistent with the liquidation provisions of the underlying operating and partnership agreements, which can be based on complex income tax rules and regulations.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's review of the HLBV model, including controls related to review of the setup and accounting of the partnership liquidation model in relation to the operating and partnership agreement provisions, as well as the applicable tax regulations. We read the operating and partnership agreements and compared them against the Company's partnership liquidation model for the corresponding tax equity financing arrangement. We involved tax professionals with specialized skills and knowledge, who assisted in:

- analyzing the tax status of the entities and the requirements of the operating and partnership agreement provisions, as well as the partnership tax regulations
- evaluating the Company's methodology for calculating the hypothetical liquidation amounts for a partnership in accordance with the operating and partnership agreement provisions, as well as the partnership tax regulations.

/s/ KPMG LLP

We have served as the Company's auditor since 2017.

New York, New York
March 1, 2021

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Avangrid, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited Avangrid, Inc. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2020 and 2019, the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes and financial statement schedule I (collectively, the consolidated financial statements), and our report dated March 1, 2021 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Report of Management on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

New York, New York
March 1, 2021

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Income

Years Ended December 31,	2020	2019	2018
(Millions, except for number of shares and per share data)			
Operating Revenues	**$ 6,320**	**$ 6,336**	**$ 6,477**
Operating Expenses			
Purchased power, natural gas and fuel used	1,379	1,509	1,653
Operations and maintenance	2,466	2,305	2,258
Loss from assets held for sale	—	—	16
Depreciation and amortization	987	933	855
Taxes other than income taxes, net	619	591	579
Total Operating Expenses	**5,451**	**5,338**	**5,361**
Operating Income	**869**	**998**	**1,116**
Other Income and (Expense)			
Other income (expense)	18	121	(66)
(Losses) earnings from equity method investments	(3)	3	10
Interest expense, net of capitalization	(316)	(310)	(303)
Income Before Income Tax	**568**	**812**	**757**
Income tax expense	29	169	167
Net Income	**539**	**643**	**590**
Net loss (income) attributable to noncontrolling interests	42	24	(3)
Net Income Attributable to Avangrid, Inc.	**$ 581**	**$ 667**	**$ 587**
Earnings Per Common Share, Basic:	**$ 1.88**	**$ 2.16**	**$ 1.90**
Earnings Per Common Share, Diluted:	**$ 1.88**	**$ 2.16**	**$ 1.89**
Weighted-average Number of Common Shares Outstanding:			
Basic	309,494,939	309,491,082	309,503,319
Diluted	309,559,387	309,514,910	309,712,628

The accompanying notes are an integral part of our consolidated financial statements.

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income

Years Ended December 31,	2020	2019	2018
(Millions)			
Net Income	**$ 539**	**$ 643**	**$ 590**
Other Comprehensive Income			
Gain on defined benefit plans, net of income taxes of $0, $0 and $1, respectively	—	1	3
Amortization of pension cost for nonqualified plans, net of income taxes of $3, $(1) and $0, respectively	(13)	(1)	1
Unrealized loss during the year on derivatives qualifying as cash flow hedges, net of income taxes of $(7), $(9) and $(7), respectively	(22)	(22)	(21)
Reclassification to net income of losses (gains) on cash flow hedges, net of income taxes of $2, $3 and $(7), respectively	19	11	(8)
Other Comprehensive Loss	**(16)**	**(11)**	**(25)**
Comprehensive Income	523	632	565
Net loss (income) attributable to noncontrolling interests	42	24	(3)
Comprehensive Income Attributable to Avangrid, Inc.	**$ 565**	**$ 656**	**$ 562**

The accompanying notes are an integral part of our consolidated financial statements.

Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2020	2019
(Millions)		
Assets		
Current Assets		
Cash and cash equivalents	$ 1,463	$ 178
Accounts receivable and unbilled revenues, net	1,187	1,082
Accounts receivable from affiliates	12	10
Derivative assets	18	11
Fuel and gas in storage	93	110
Materials and supplies	169	141
Prepayments and other current assets	525	199
Regulatory assets	310	294
Total Current Assets	**3,777**	**2,025**
Total Property, Plant and Equipment ($1,637 and $787 related to VIEs, respectively)	**26,751**	**25,196**
Operating lease right-of-use assets	153	70
Equity method investments	668	645
Other investments	68	63
Regulatory assets	2,572	2,567
Other Assets		
Goodwill	3,119	3,119
Intangible assets	305	314
Derivative assets	79	84
Other	331	311
Total Other Assets	**3,834**	**3,828**
Total Assets	**$ 37,823**	**$ 34,394**

The accompanying notes are an integral part of our consolidated financial statements.

Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2020	2019
(Millions, except share information)		
Liabilities		
Current Liabilities		
Current portion of debt	$ 313	$ 730
Notes payable	307	560
Interest accrued	70	72
Accounts payable and accrued liabilities	1,453	1,361
Accounts payable to affiliates	50	64
Dividends payable	136	136
Taxes accrued	73	56
Operating lease liabilities	8	12
Derivative liabilities	17	20
Other current liabilities	368	336
Regulatory liabilities	274	242
Total Current Liabilities	**3,069**	**3,589**
Regulatory liabilities	3,137	3,281
Other Non-current Liabilities		
Deferred income taxes	1,919	1,837
Deferred income	1,204	1,274
Pension and other postretirement	1,007	1,100
Operating lease liabilities	154	65
Derivative liabilities	79	85
Asset retirement obligations	210	190
Environmental remediation costs	292	338
Other	448	380
Total Other Non-current Liabilities	**5,313**	**5,269**
Non-current debt	7,478	6,716
Non-current debt to affiliate	3,000	—
Total Non-current Liabilities	**18,928**	**15,266**
Total Liabilities	**21,997**	**18,855**
Commitments and Contingencies	—	—
Equity		
Stockholders' Equity:		
Common stock, $.01 par value, 500,000,000 shares authorized, 309,794,917 and 309,752,140 shares issued; 309,077,300 and 309,005,272 shares outstanding, respectively	3	3
Additional paid-in capital	13,665	13,660
Treasury stock	(14)	(12)
Retained earnings	1,666	1,634
Accumulated other comprehensive loss	(111)	(95)
Total Stockholders' Equity	**15,209**	**15,190**
Noncontrolling interests	617	349
Total Equity	**15,826**	**15,539**
Total Liabilities and Equity	**$ 37,823**	**$ 34,394**

The accompanying notes are an integral part of our consolidated financial statements.

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

Years Ended December 31,	2020	2019	2018
(Millions)			
Cash Flow from Operating Activities			
Net income	**$ 539**	**$ 643**	**$ 590**
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	987	933	855
Loss from assets held for sale	—	—	16
Accretion expenses	11	12	12
Regulatory assets/liabilities amortization and carrying cost	(13)	64	73
Pension cost	82	91	123
Earnings from equity method investments	3	(3)	(10)
Distribution of earnings from equity method investments	19	12	14
Unrealized losses (gains) on marked to market derivative contracts	5	(76)	22
Gain from divestment and disposal of property	(10)	(135)	(10)
Deferred taxes	17	164	148
Other non-cash items	(83)	(51)	(27)
Changes in operating assets and liabilities:			
Current assets	(173)	126	(117)
Noncurrent assets	(170)	(152)	(87)
Current liabilities	160	(2)	99
Noncurrent liabilities	(86)	(38)	80
Net Cash Provided by Operating Activities	**1,288**	**1,588**	**1,781**
Cash Flow from Investing Activities			
Capital expenditures	(2,781)	(2,735)	(1,777)
Contributions in aid of construction	48	74	60
Proceeds from sale of equity method and other investment	238	108	186
Proceeds from sale of property, plant and equipment	7	18	18
Payments to affiliates	(3)	(2)	—
Cash distribution from equity method investments	3	5	4
Other investments and equity method investments, net	(370)	(176)	(45)
Net Cash Used in Investing Activities	**(2,858)**	**(2,708)**	**(1,554)**
Cash Flow from Financing Activities			
Non-current debt issuances	1,367	2,137	597
Non-current debt issuance with affiliate	3,000	—	—
Repayments of non-current debt	(1,011)	(346)	(217)
Repayments of other short-term debt, net	(253)	(28)	(201)
Repayments of financing leases	(9)	(27)	(13)
Repurchase of common stock	(2)	—	(4)
Issuance of common stock	(1)	—	(2)
Distributions to noncontrolling interests	(5)	(63)	(76)
Contributions from noncontrolling interests	312	133	223
Dividends paid	(545)	(545)	(537)
Net Cash Provided by (Used in) Financing Activities	**2,853**	**1,261**	**(230)**
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	**1,283**	**141**	**(3)**
Cash, Cash Equivalents and Restricted Cash, Beginning of Year	**184**	**43**	**46**
Cash, Cash Equivalents and Restricted Cash, End of Year	**$ 1,467**	**$ 184**	**$ 43**
Supplemental Cash Flow Information			
Cash paid for interest, net of amounts capitalized	$ 278	$ 270	$ 224
Cash paid (refunded) for income taxes	$ 8	$ 2	$ (13)

The accompanying notes are an integral part of our consolidated financial statements.

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Changes in Equity

	Avangrid, Inc. Stockholders								
(Millions, except for number of shares)	Number of shares (*)	Common Stock	Additional paid-in capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Non-controlling Interests	Total Equity
Balances, December 31, 2017	**309,005,272**	**$ 3**	**$ 13,653**	**$ (8)**	**$ 1,469**	**$ (46)**	**$ 15,071**	**$ 19**	**$ 15,090**
Adoption of accounting standards	—	—	—	—	(3)	(1)	(4)	140	136
Net income	—	—	—	—	587	—	587	3	590
Other comprehensive income, net of tax of $(13)	—	—	—	—	—	(25)	(25)	—	(25)
Comprehensive income									565
Dividends declared, $1.744/share	—	—	—	—	(540)	—	(540)	—	(540)
Issuance of common stock	81,208	—	1	—	(3)	—	(2)	—	(2)
Repurchase of common stock	(81,208)	—	—	(4)	—	—	(4)	—	(4)
Stock-based compensation	—	—	3	—	—	—	3	—	3
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(76)	(76)
Contributions from noncontrolling interests	—	—	—	—	4	—	4	213	217
Balances, December 31, 2018	**309,005,272**	**3**	**13,657**	**(12)**	**1,514**	**(72)**	**15,090**	**299**	**15,389**
Adoption of accounting standards	—	—	—	—	11	(12)	(1)	—	(1)
Net income	—	—	—	—	667	—	667	(24)	643
Other comprehensive income, net of tax of $(7)	—	—	—	—	—	(11)	(11)	—	(11)
Comprehensive income									632
Dividends declared, $1.76/share	—	—	—	—	(545)	—	(545)	—	(545)
Stock-based compensation	—	—	3	—	—	—	3	—	3
Distributions to noncontrolling interests	—	—	—	—	(4)	—	(4)	(59)	(63)
Contributions from noncontrolling interests	—	—	—	—	(9)	—	(9)	133	124
Balances, December 31, 2019	**309,005,272**	**3**	**13,660**	**(12)**	**1,634**	**(95)**	**15,190**	**349**	**15,539**
Adoption of accounting standards	—	—	—	—	(1)	—	(1)	—	(1)
Net income	—	—	—	—	581	—	581	(42)	539
Other comprehensive income, net of tax of $(2)	—	—	—	—	—	(16)	(16)	—	(16)
Comprehensive income									523
Dividends declared, $1.76/share	—	—	—	—	(545)	—	(545)	—	(545)
Release of common stock held in trust	72,028	—	—	—	—	—	—	—	—
Issuance of common stock	42,777	—	(1)	—	—	—	(1)	—	(1)
Repurchase of common stock	(42,777)	—	—	(2)	—	—	(2)	—	(2)
Stock-based compensation	—	—	6	—	—	—	6	—	6
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(5)	(5)
Contributions from noncontrolling interests	—	—	—	—	(3)	—	(3)	315	312
Balances, December 31, 2020	**309,077,300**	**$ 3**	**$ 13,665**	**$ (14)**	**$ 1,666**	**$ (111)**	**$ 15,209**	**$ 617**	**$ 15,826**

(*) Par value of share amounts is $.01

The accompanying notes are an integral part of our consolidated financial statements.

Note 1. Background and Nature of Operations

Avangrid, Inc. (AVANGRID, we or the Company) is an energy services holding company engaged in the regulated energy transmission and distribution business through its principal subsidiary Avangrid Networks, Inc. (Networks), and in the renewable energy generation business through its principal subsidiary, Avangrid Renewables Holding, Inc. (ARHI). ARHI in turn holds subsidiaries including Avangrid Renewables, LLC (Renewables). Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain, owns 81.5% of the outstanding common stock of AVANGRID. The remaining outstanding shares are publicly-traded on the New York Stock Exchange and owned by various shareholders.

Proposed Merger with PNMR

On October 20, 2020, AVANGRID, PNM Resources, Inc., a New Mexico corporation (PNMR) and NM Green Holdings, Inc., a New Mexico corporation and wholly-owned subsidiary of AVANGRID (Merger Sub), entered into an Agreement and Plan of Merger (Merger Agreement), pursuant to which Merger Sub is expected to merge with and into PNMR, with PNMR surviving the Merger as a direct wholly-owned subsidiary of AVANGRID (Merger). Pursuant to the Merger Agreement, each issued and outstanding share of the common stock of PNMR (PNMR common stock) (other than (i) the issued shares of PNMR common stock that are owned by AVANGRID, Merger Sub, PNMR or any wholly-owned subsidiary of AVANGRID or PNMR, which will be automatically cancelled at the time the Merger is consummated and (ii) shares of PNMR common stock held by a holder who has not voted in favor of, or consented in writing to, the Merger who is entitled to, and who has demanded, payment for fair value of such shares) will be converted, at the time the Merger is consummated, into the right to receive $50.30 in cash (Merger Consideration).

Consummation of the Merger (Closing) is subject to the satisfaction or waiver of certain customary closing conditions, including, without limitation, the approval of the Merger Agreement by the holders of at least a majority of the outstanding shares of PNMR common stock entitled to vote thereon, the absence of any material adverse effect on PNMR, the receipt of certain required regulatory approvals (including approvals from the Public Utility Commission of Texas (PUCT), the New Mexico Public Regulation Commission (NMPRC), the FERC, the Federal Communications Commission (FCC), the Committee on Foreign Investment in the United States (CFIUS), the Nuclear Regulatory Commission (NRC) and approval under the Hart-Scott-Rodino Antitrust Improvements Act of 1976), the Four Corners Divestiture Agreements (as defined below) being in full force and effect and all applicable regulatory filings associated therewith being made, as well as holders of no more than 15% of the outstanding shares of PNMR common stock validly exercising their dissenters' rights. On February 12, 2021, the shareholders of PNMR approved the proposed Merger. The Merger is currently expected to close in the second half of 2021.

The Merger Agreement also contains representations, warranties and covenants of PNMR, AVANGRID and Merger Sub, which are customary for transactions of this type. In addition, among other things, the Merger Agreement contains a covenant requiring PNMR to, prior to the Closing, enter into agreements (Four Corners Divestiture Agreements) providing for, and to make filings required to, exit from all ownership interests in the Four Corners Power Plant, all with the objective of having the closing date for such exit be no later than December 31, 2024.

In connection with the Merger, Iberdrola, S.A. has provided AVANGRID a commitment letter (Iberdrola Funding Commitment Letter), pursuant to which Iberdrola has unilaterally agreed to provide to AVANGRID, or arrange the provision to AVANGRID of, funds to the extent necessary for AVANGRID to consummate the Merger, including the payment of the aggregate Merger Consideration. To the extent AVANGRID wishes to effect a funding transaction under the Iberdrola Funding Commitment Letter in order to pay the Merger Consideration, the specific terms of any such transaction will be negotiated between Iberdrola and AVANGRID on an arm's length basis and must be approved by both (i) a majority of the members of the unaffiliated committee of the board of directors of AVANGRID, and (ii) a majority of the board of directors of AVANGRID. Under the terms of such commitment letter, Iberdrola S.A. has agreed to negotiate with AVANGRID the specific terms of any transaction effecting such funding commitment promptly and in good faith, with the objective that such terms shall be commercially reasonable and approved by AVANGRID. AVANGRID's and Merger Sub's obligations under the Merger Agreement are not conditioned upon AVANGRID obtaining financing.

The Merger Agreement provides for certain customary termination rights including the right of either party to terminate the Merger Agreement if the Merger is not completed on or before January 20, 2022 (subject to a three-month extension by either party if all of the conditions to the closing, other than the conditions related to obtaining regulatory approvals, have been satisfied or waived). The Merger Agreement further provides that, upon termination of the Merger Agreement under certain specified circumstances (including if AVANGRID terminates the Merger Agreement due to a change in recommendation of the board of directors of PNMR or if PNMR terminates the Merger Agreement to accept a superior proposal (as defined in the

Merger Agreement)), PNMR will be required to pay AVANGRID a termination fee of $130 million. In addition, the Merger Agreement provides that (i) if the Merger Agreement is terminated by either party due to a failure of a regulatory closing condition and such failure is the result of AVANGRID's breach of its regulatory covenants, or (ii) AVANGRID fails to effect the Closing when all closing conditions have been satisfied and it is otherwise obligated to do so under the Merger Agreement, then, in either such case, upon termination of the Merger Agreement, AVANGRID will be required to pay PNMR a termination fee of $184 million as the sole and exclusive remedy. Upon the termination of the Merger Agreement under certain specified circumstances involving a breach of the Merger Agreement, either PNMR or AVANGRID will be required to reimburse the other party's reasonable and documented out-of-pocket fees and expenses up to $10 million (which amount will be credited toward, and offset against, the payment of any applicable termination fee).

Note 2. Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with U.S. GAAP and are presented on a consolidated basis, and therefore include the accounts of AVANGRID and its consolidated subsidiaries, Networks and ARHI. All intercompany transactions and accounts have been eliminated in consolidation in all periods presented.

Immaterial Corrections to Prior Periods

We have identified various immaterial corrections to prior periods primarily related to property, plant and equipment and deferred tax liabilities that originated in prior periods. We evaluated the effects of these corrections on our previously-issued consolidated financial statements, individually and in the aggregate, in accordance with the guidance in ASC Topic 250, Accounting Changes and Error Corrections, ASC Topic 250-10-S99-1, Assessing Materiality, and ASC Topic 250-10-S99-2, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, and concluded that no prior period is materially misstated. Accordingly, we have revised our consolidated financial statements for the prior periods presented herein. The revision decreased retained earnings by $6 million as of December 31, 2018.

A summary of the effect of the correction on the consolidated balance sheet as of December 31, 2019 is as follows:

As of December 31, 2019	As reported	Correction	As Revised
(Millions)			
Assets			
Total Property, Plant and Equipment	$ 25,218	$ (22)	$ 25,196
Total Assets	$ 34,416	$ (22)	$ 34,394
Liabilities			
Other current liabilities	$ 334	$ 2	$ 336
Total Current Liabilities	$ 3,587	$ 2	$ 3,589
Deferred income taxes	$ 1,814	$ 23	$ 1,837
Total Other Non-current Liabilities	$ 5,246	$ 23	$ 5,269
Total Non-current Liabilities	$ 15,243	$ 23	$ 15,266
Total Liabilities	$ 18,830	$ 25	$ 18,855
Equity			
Retained earnings	$ 1,681	$ (47)	$ 1,634
Total Stockholders' Equity	$ 15,237	$ (47)	$ 15,190
Total Equity	$ 15,586	$ (47)	$ 15,539
Total Liabilities and Equity	$ 34,416	$ (22)	$ 34,394

A summary of the effect of the correction on the consolidated statements of income for the year ended December 31, 2019 is as follows:

Year Ended December 31, 2019	As reported	Correction	As Revised
(Millions)			
Operating Revenues	$ 6,338	$ (2)	$ 6,336
Operations and maintenance	$ 2,301	$ 4	$ 2,305
Depreciation and amortization	$ 934	$ (1)	$ 933
Total Operating Expenses	$ 5,335	$ 3	$ 5,338
Operating Income	$ 1,003	$ (5)	$ 998
Other income	$ 119	$ 2	$ 121
Interest expense, net of capitalization	$ (306)	$ (4)	$ (310)
Income Before Income Tax	$ 819	$ (7)	$ 812
Income tax expense	$ 143	$ 26	$ 169
Net Income	$ 676	$ (33)	$ 643
Net Income Attributable to Avangrid, Inc.	$ 700	$ (33)	$ 667
Earnings per common share, Basic	$ 2.26	$ (0.10)	$ 2.16
Earnings per common share, Diluted	$ 2.26	$ (0.10)	$ 2.16

A summary of the effect of the correction on the consolidated statements of income for the year ended December 31, 2018 is as follows:

Year Ended December 31, 2018	As reported	Correction	As Revised
(Millions)			
Operating Revenues	$ 6,478	$ (1)	$ 6,477
Operations and maintenance	$ 2,248	$ 10	$ 2,258
Total Operating Expenses	$ 5,351	$ 10	$ 5,361
Operating Income	$ 1,127	$ (11)	$ 1,116
Income Before Income Tax	$ 768	$ (11)	$ 757
Income tax expense	$ 170	$ (3)	$ 167
Net Income	$ 598	$ (8)	$ 590
Net Income Attributable to Avangrid, Inc.	$ 595	$ (8)	$ 587
Earnings per common share, Basic	$ 1.92	$ (0.02)	$ 1.90
Earnings per common share, Diluted	$ 1.92	$ (0.03)	$ 1.89

A summary of the effect of the correction on the consolidated statements of cash flows for the years ended December 31, 2019 and 2018 is as follows:

Years Ended December 31,	2019			2018		
(Millions)	As Reported	Correction	As Revised	As Reported	Correction	As Revised
Net income	$ 676	$ (33)	$ 643	$ 598	$ (8)	$ 590
Depreciation and amortization	$ 934	$ (1)	$ 933	$ 855	$ —	$ 855
Deferred taxes	$ 138	$ 26	$ 164	$ 151	$ (3)	$ 148
Current liabilities	$ (5)	$ 3	$ (2)	$ 98	$ 1	$ 99
Net Cash Provided by Operating Activities	$ 1,593	$ (5)	$ 1,588	$ 1,791	$ (10)	$ 1,781
Capital expenditures	$ (2,740)	$ 5	$ (2,735)	$ (1,787)	$ 10	$ (1,777)
Net Cash Used in Investing Activities	$ (2,713)	$ 5	$ (2,708)	$ (1,564)	$ 10	$ (1,554)
Cash paid for interest, net of amounts capitalized	$ 266	$ 4	$ 270	$ 224	$ —	$ 224

Note 3. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

Significant Accounting Policies

We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our consolidated financial statements:

(a) Principles of consolidation

We consolidate the entities in which we have a controlling financial interest, after the elimination of intercompany transactions. We account for investments in common stock where we have the ability to exercise significant influence, but not control, using the equity method of accounting.

(b) Revenue recognition

We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

(c) Regulatory accounting

We account for our regulated utilities' operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and can be collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our consolidated statements of income consistent with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

(d) Business combinations and assets acquisitions (disposals)

We apply the acquisition method of accounting to account for business combinations. The consideration transferred for an acquisition is the fair value of the assets transferred, the liabilities incurred, including contingent consideration, and the equity interests issued by the acquirer. We measure identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination initially at their fair values at the acquisition date. We record as goodwill the excess of the consideration transferred over the fair value of the identifiable net assets acquired. We recognize adjustments to provisional amounts relating to a business combination that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. For business combinations, we expense acquisition-related costs as incurred.

In contrast to a business combination (disposal), we classify a transaction as an asset acquisition (disposal) when substantially all the fair value of the gross assets acquired (disposed) is concentrated in a single identifiable asset or group of similar identifiable assets or otherwise does not meet the definition of a business. For asset acquisitions, we capitalize acquisition-related costs as a component of the cost of the assets acquired and liabilities assumed.

(e) Noncontrolling interests

Noncontrolling interests represent the portion of our net income (loss), comprehensive income (loss) and net assets that is not allocable to us and is calculated based on our ownership percentage. For holdings where the economic allocations are not based pro rata on ownership percentages, we use the balance sheet-oriented hypothetical liquidation at book value (HLBV) method, to reflect the substantive profit sharing arrangement.

Under the HLBV method, the amounts we report as "Noncontrolling interests" and "Net income (loss) attributable to noncontrolling interests" in our consolidated balance sheets and consolidated statements of income represent the amounts the noncontrolling interest would hypothetically receive at each balance sheet reporting date under the liquidation provisions of each holding's ownership agreement assuming we were to liquidate the net assets of the projects at recorded amounts determined in accordance with U.S. GAAP and distribute those amounts to the investors. We determine the noncontrolling interest in our statements of income and comprehensive income as the difference in noncontrolling interests on our consolidated balance sheets at the start, or at inception of the noncontrolling interest if applicable, and end of each reporting period, after taking into account any capital transactions between the holdings and the third party. We report the noncontrolling interest balances in the holdings as a component of equity on our consolidated balance sheets.

(f) Equity method investments

We account for joint ventures that do not meet consolidation criteria using the equity method. We reflect earnings (losses) recognized under the equity method in the consolidated statements of income as "Earnings (losses) from equity method investments." We recognize dividends received from joint ventures as a reduction in the carrying amount of the investment and not as dividend income. We assess and record an impairment of our equity method investments in earnings for a decline in value that we determine to be other than temporary.

(g) Goodwill and other intangible assets

Goodwill represents future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred, the fair value of any noncontrolling interest and the acquisition date fair value of any previously held equity interest in the acquiree over the fair value of the net identifiable assets acquired and liabilities assumed.

Goodwill is not amortized, but is subject to an assessment for impairment performed in the fourth quarter or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of a reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which we test goodwill for impairment. In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

Intangible assets acquired separately are measured on initial recognition at cost. The cost of intangible assets acquired in a business combination is their fair value at the date of acquisition. Following initial recognition, intangible assets are carried at cost less any accumulated amortization and impairment losses. The useful lives of intangible assets are assessed as either finite or indefinite.

Intangible assets with finite lives are amortized on a straight-line basis over the useful economic life, which ranges from four to forty years, and assessed for impairment whenever there is an indication that the intangible asset may be impaired. The amortization expense on intangible assets with finite lives is recognized in our consolidated statements of income within the expense category that is consistent with the function of the intangible assets.

(h) Property, plant and equipment

We account for property, plant and equipment at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

We transfer assets from “Construction work in progress” to “Property, plant and equipment” when they are available for service.

We capitalize wind turbine and related equipment costs, other project construction costs and interest costs related to the project during the construction period through substantial completion. We record AROs at the date projects achieve commercial operation.

We depreciate the cost of plant and equipment in use on a straight-line basis, less any estimated residual value. The main asset categories are depreciated over the following estimated useful lives:

Major class	Asset Category	Estimated Useful Life (years)
Plant	Combined cycle plants	35-55
	Hydroelectric power stations	45-90
	Wind power stations	25-40
	Solar power stations	25
	Transport facilities	40-75
	Distribution facilities	15-80
Equipment	Conventional meters and measuring devices	7-60
	Computer software	4-25
Other	Buildings	30-82
	Operations offices	5-75

Networks determines depreciation expense using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal, in service at each operating company. Consistent with FERC accounting requirements, Networks charges the original cost of utility plant retired or otherwise disposed to accumulated depreciation. Networks' composite rate of depreciation was 2.9% of average depreciable property for both 2020 and 2019.

We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC), applicable to Networks' entities that apply regulatory accounting, is a noncash item that represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and record the remainder as other income.

(i) Leases

We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our consolidated balance sheets, we include, for operating leases: "Operating lease right-of-use (ROU) assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. Most of our leases do not provide an implicit rate, so we use our incremental borrowing rate based on the information available at the lease commencement date to determine the present value of future payments. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the balance sheet for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes an option to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or for our regulated companies we recognize the amount eligible for recovery under their rate plans, such as actual amounts paid. We amortize finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

(j) Impairment of long-lived assets

We evaluate property, plant and equipment and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. We are required to recognize an impairment loss if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long-lived asset exceeds the asset's fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow (DCF) model, with assumptions consistent with a market participant's view of the exit price of the asset.

(k) Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the consolidated financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

(l) Equity investments with readily determinable fair values

We measure equity investments with readily determinable fair values at fair value, with changes in fair value reported in net income.

(m) Derivatives and hedge accounting

Derivatives are recognized on our consolidated balance sheets at their fair value, except for certain electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that qualify for, and are elected under, the normal purchases and normal sales exception. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. We recognize changes in the fair value of a derivative contract in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. We report the gain or loss on the derivative instrument as a component of Other Comprehensive Income (OCI) and later reclassify amounts into earnings when the underlying transaction occurs, which we present in the same income statement line item as the earnings effect of the hedged item. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, we will discontinue hedge accounting prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, we immediately recognize in earnings hedge gains and losses previously recorded in OCI.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. For our regulated operations, we record changes in the fair value of electric and natural gas hedge contracts derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities.

We offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

(n) Cash and cash equivalents

Cash and cash equivalents include cash, bank accounts and other highly-liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in “Cash and cash equivalents.” Restricted cash represents cash legally set aside for a specified purpose or as part of an agreement with a third party. Restricted cash is included in “Other non-current assets” on our consolidated balance sheets. We classify book overdrafts representing outstanding checks in excess of funds on deposit as “Accounts payable and accrued liabilities” on our consolidated balance sheets. We report changes in book overdrafts in the operating activities section of our consolidated statements of cash flows.

(o) Trade receivable and unbilled revenue, net of allowance for credit losses

We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. Certain trade receivables and payables related to our wholesale activities associated with generation and delivery of electric energy and associated environmental attributes, origination and marketing, natural gas storage, hub services and energy management, are subject to master netting agreements with counterparties, whereby we have the legal right to offset the balances and they are settled on a net basis. We present receivables and payables subject to such agreements on a net basis on our consolidated balance sheets.

Trade receivables include amounts due under Deferred Payment Arrangements (DPA). A DPA allows the account balance to be paid in installments over an extended period without interest, which generally exceeds one year, by negotiating mutually acceptable payment terms. The utility companies generally must continue to serve a customer who cannot pay an account balance in full if the customer (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short term. Due to COVID-19, the UIL companies’ regulators require them to offer to customers, through early February 2021, a 24-month repayment plan.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. Due to our adoption of Accounting Standards Codification (ASC) 326 effective January 1, 2020, we now also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts.

(p) Variable interest entities

An entity is considered to be a variable interest entity (VIE) when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. A reporting company is required to consolidate a VIE as its primary beneficiary when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and the obligation to absorb losses of or the right to receive benefits from the VIE that could potentially be significant to the VIE. We evaluate whether an entity is a VIE whenever reconsideration events occur as defined by the accounting guidance (See Note 20).

We have undertaken several structured institutional partnership investment transactions that bring in external investors in certain of our wind farms in exchange for cash. Following an analysis of the economic substance of these transactions, we classify the consideration received at the inception of the arrangement as noncontrolling interests on our consolidated balance sheets. Subsequently, we use the HLBV method to allocate earnings to the noncontrolling interest, taking into consideration the cash and tax benefits provided to the tax equity investors.

(q) Debentures, bonds and bank borrowings

We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings net of unamortized discount, premium and debt issuance costs on our consolidated balance sheets.

(r) Inventory

Inventory comprises fuel and gas in storage and materials and supplies. Through our gas operations, we own natural gas that is stored in third-party owned underground storage facilities, which we record as inventory. We price injections of inventory into storage at the market purchase cost at the time of injection, and price withdrawals of working gas from storage at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. We report inventories to support gas operations on our consolidated balance sheets within "Fuel and gas in storage."

We also have materials and supplies inventories that we use for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on our consolidated balance sheets within "Materials and supplies."

In addition, stand-alone renewable energy credits that are generated or purchased and held for sale are recorded at the lower of cost or net realizable value and are reported on our consolidated balance sheets within "Materials and supplies."

(s) Government grants

Our unregulated subsidiaries record government grants related to depreciable assets within deferred income and subsequently amortize them to earnings as an offset to depreciation and amortization expense over the useful life of the related asset. Our regulated subsidiaries record government grants as a reduction to the related utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in our consolidated statements of income in the period in which we incur the expenses.

(t) Deferred income

Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our consolidated balance sheets and amortize them into earnings when revenue recognition criteria are met.

(u) Asset retirement obligations

We record the fair value of the liability for an ARO and a conditional ARO in the period in which it is incurred, capitalizing the cost by increasing the carrying amount of the related long-lived asset. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of asbestos, polychlorinated biphenyl-contaminated equipment, gas pipeline, cast iron gas mains and electricity generation facilities. We adjust the liability periodically to reflect revisions to either the timing or amount of the original estimated undiscounted cash flows over time. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement, we will either settle the obligation at its recorded amount or incur a gain or a loss. Our regulated utilities defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the entity's control. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

Our regulated utilities meet the requirements concerning accounting for regulated operations and we recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify these as accrued removal obligations.

(v) Environmental remediation liability

In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2056.

(w) Post-employment and other employee benefits

We sponsor defined benefit pension plans that cover eligible employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. Our utility operations generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in other comprehensive income, as management believes it is probable that such items will be recoverable through the ratemaking process. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over the average remaining service period or 10 years, considering any requirement by the regulators for our Networks subsidiaries. Our policy is to calculate the expected return on plan assets using the market related value of assets. That value is determined by recognizing the difference between actual returns and expected returns over a five-year period.

(x) Income taxes

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, certain of our regulated subsidiaries have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer the investment tax credits (ITCs) when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. Changes in deferred income tax assets and liabilities that are associated with components of OCI are charged or credited directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit. Deferred tax assets and liabilities are netted and classified as non-current on our consolidated balance sheets.

We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in "Taxes other than income taxes" and "Taxes accrued" in our consolidated financial statements.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within "Interest expense, net of capitalization" and "Other income and (expense)" in our consolidated statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. In 2019, we netted our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

Federal production tax credits applicable to our renewable energy facilities, that are not part of a tax equity financing arrangement, are recognized as a reduction in income tax expense with a corresponding reduction in deferred income tax liabilities.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management's best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

(y) Stock-based compensation

Stock-based compensation represents costs related to stock-based awards granted to employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

Adoption of New Accounting Pronouncements

(a) Measurement of credit losses on financial instruments, amendments and updates

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments (ASC 326). The amendments affect entities that hold financial assets and net investment in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, net investments in leases, off-balance-sheet credit exposures, etc.). They require an entity to present a financial asset (or group of financial assets) that is measured at amortized cost basis at the net amount expected to be collected. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. The income statement reflects the measurement of credit losses for newly recognized financial assets, as well as the expected increases or decreases of expected credit losses that have taken place during the period. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions and reasonable and supportable forecasts that affect the collectability of the reported amount. An entity must use judgment in determining the relevant information and estimation methods appropriate in its circumstances. The FASB subsequently issued various updates to ASC 326 to clarify transition and scope requirements, make narrow-scope codification improvements, including in March 2020, and corrections and provide targeted transition relief. We adopted the amendments effective January 1, 2020, including the narrow-scope improvements issued in March 2020, and recorded a cumulative-effect adjustment of $1 million to retained earnings at the beginning of the period of adoption, with no material effect to our consolidated results of operations, financial position, cash flows and disclosures.

(b) Simplifying the test for goodwill impairment

In January 2017, the FASB issued amendments to simplify the test for goodwill impairment, which is required for public entities and certain other entities that have goodwill reported in their financial statements. The amendments simplify the subsequent measurement of goodwill by eliminating Step 2 from the goodwill impairment test, which requires the valuation of assets acquired and liabilities assumed using business combination accounting guidance. Under the new guidance, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Also, an entity should consider income tax effects from any tax-deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. Certain requirements are eliminated for any reporting unit with a zero or negative carrying amount; therefore, the same impairment assessment applies to all reporting units. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. We adopted the amendments effective January 1, 2020, with no material effect to our consolidated results of operations, financial position, cash flows and disclosures. As required, we are applying the amendments on a prospective basis.

(c) Changes to the disclosure requirements for fair value measurement and defined benefit plans

In August 2018, the FASB issued amendments related to disclosure requirements for both fair value measurement and defined benefit plans.

The amendments concerning fair value measurement remove, modify and add certain disclosure requirements in order to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. We adopted the amendments effective January 1, 2020, with no material effect to our disclosures. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively.

The amendments concerning disclosure requirements for defined benefit plans are narrow in scope and apply to all employers that sponsor defined benefit pension or other postretirement plans. The amendments change annual disclosures requirements, including removal of disclosures that are no longer considered cost beneficial, adding certain new relevant disclosures and clarifying specific requirements of disclosures concerning information for defined benefit pension plans. We adopted the amendments effective January 1, 2020, and they will not materially affect the disclosures for our fiscal year ending December 31, 2020. As required, we applied the amendments on a retrospective basis.

(d) Targeted improvements to related party guidance for VIEs

In October 2018, the FASB issued amendments that affect reporting entities that are required to determine whether they should consolidate a legal entity under the consolidation guidance applicable to VIEs. The targeted improvements specifically applicable to public business entities clarify that indirect interests held through related parties in common control arrangements should be considered on a proportional basis for determining whether fees paid to decision makers and service providers are variable interests. We adopted the amendments effective January 1, 2020, with no material effect to our consolidated results of operations, financial position, cash flows and disclosures.

(e) Clarifying guidance for certain collaborative arrangements with respect to revenue recognition

The FASB issued amendments in November 2018 to clarify the interaction between the guidance for certain collaborative arrangements and the guidance applicable to ASC 606. A collaborative arrangement is a contractual arrangement under which two or more parties actively participate in a joint operating activity and are exposed to significant risks and rewards that depend on the activity's commercial success. The targeted improvements clarify that certain transactions between collaborative arrangement participants are within the scope of ASC 606 and thus subject to all its guidance. We adopted the amendments effective January 1, 2020, with no material effect to our consolidated results of operations, financial position, cash flows and disclosures. As required, we retrospectively applied the amendments to the date of our initial application of ASC 606.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on our consolidated financial statements.

(a) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, *Income Taxes*, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation, (2) exceptions to accounting for basis differences in equity method investments when there are ownership changes in foreign investments and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U. S. GAAP for (1) franchise taxes that are partially based on income, (2) transactions with a government that result in a step up in the tax basis of goodwill, (3) separate financial statements of legal entities that are not subject to tax and (4) enacted changes in tax laws in interim periods. The amendments are effective for public business entities for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued, with adoption of all amendments in the same period. Application is on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment aspect. We expect our adoption will not materially affect our consolidated results of operations, financial position and cash flows.

(b) Facilitation of the effects of reference rate reform on financial reporting, and subsequent scope clarification

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the "discounting transition," may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments are effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

We expect our adoption of reference rate reform and the subsequent scope clarification will not materially affect our consolidated results of operations, financial position and cash flows.

Use of Estimates and Assumptions

The preparation of our consolidated financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for credit losses and unbilled revenues; (2) asset impairments, including goodwill; (3) investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers' compensation and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) fair value measurements; (10) earnings sharing mechanisms; (11) environmental remediation liabilities; (12) AROs; (13) pension and other postretirement employee benefits and (14) noncontrolling interest balances. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates we use in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as necessary. Actual results could differ from those estimates.

We continue to utilize information reasonably available to us; however, the business and economic uncertainty resulting from COVID-19 has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets and goodwill for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While we have not yet had material effects of COVID-19 on our financial results, actual results could differ from those estimates, which could result in material effects to our consolidated financial statements in future reporting periods.

Union collective bargaining agreements

We have approximately 48.8% of our employees covered by a collective bargaining agreement. Agreements expiring in the coming year apply to approximately 16.0% of our employees.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any significant payment terms that are material because we receive payment at or shortly after the point of sale.

The following describes the principal activities, by reportable segment, from which we generate revenue. For more detailed information about our reportable segments, refer to Note 24.

Networks Segment

Networks derives its revenue primarily from tariff-based sales of electricity and natural gas service to customers in New York, Connecticut, Maine and Massachusetts with no defined contractual term. For such revenues, we recognize revenues in an amount derived from the commodities delivered to customers. Other major sources of revenue are electricity transmission and wholesale sales of electricity and natural gas.

Tariff-based sales are subject to the corresponding state regulatory authorities, which determine prices and other terms of service through the ratemaking process. The applicable tariffs are based on the cost of providing service. The utilities' approved base rates are designed to recover their allowable operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable return on equity. They traditionally invoice their customers by applying approved base rates to usage. Maine state law prohibits the utility from providing the electricity commodity to customers. In New York, Connecticut and Massachusetts, customers have the option to obtain the electricity or natural gas commodity directly from the utility or from another supplier. For customers that receive their commodity from another supplier, the utility acts as an agent and delivers the electricity or natural gas provided by that supplier. Revenue in those cases is only for providing the service of delivery of the commodity. Networks entities calculate revenue earned but not yet billed based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. Differences between actual and estimated unbilled revenue are immaterial.

Transmission revenue results from others' use of the utility's transmission system to transmit electricity and is subject to Federal Energy Regulatory Commission (FERC) regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts. Short-term wholesale sales of electricity are generally on a daily basis based on market prices and are administered by the Independent System Operator-New England (ISO-NE) and the New York Independent System Operator (NYISO), or PJM Interconnection, L.L.C. (PJM), as applicable. Wholesale sales of natural gas are generally short-term based on market prices through contracts with the specific customer.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as Networks delivers or sells the electricity or natural gas or provides the delivery or transmission service. We record revenue for all of such sales based upon the regulatory-approved tariff and the volume delivered or transmitted, which corresponds to the amount that we have a right to invoice. There are no material initial incremental costs of obtaining a contract in any of the arrangements. Networks does not adjust the promised consideration for the effects of a significant financing component if it expects, at contract inception, that the time between the delivery of promised goods or service and customer payment will be one year or less. For its New York and Connecticut utilities, Networks assesses its DPAs at each balance sheet date for the existence of significant financing components, but has had no material adjustments as a result.

Certain Networks entities record revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between the utilities and their regulators. The Networks ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, annual revenue requirement reconciliations and other demand side management programs. The Networks entities recognize and record only the initial recognition of "originating" ARP revenues (when the regulatory-specified conditions for recognition have been met). When they subsequently include those amounts in the price of utility service billed to customers, they record such amounts as a recovery of the associated regulatory asset or liability. When they owe amounts to customers in connection with ARPs, they evaluate those amounts on a quarterly basis and include them in the price of utility service billed to customers and do not reduce ARP revenues.

Networks also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, derivatives or ARPs.

Renewables Segment

Renewables derives its revenue primarily from the sale of energy, transmission, capacity and other related charges from its renewable wind, solar and thermal energy generating sources. For such revenues, we will recognize revenues in an amount derived from the commodities delivered and from services as they are made available. Renewables has bundled power purchase agreements consisting of electric energy, transmission, capacity and/or renewable energy credits (RECs). The related contracts are generally long-term with no stated contract amount, that is, the customer is entitled to all the unit's output. Renewables also has unbundled sales of electric energy and capacity, RECs and natural gas, which are generally for periods of less than a year. The performance obligations in substantially all of both bundled and unbundled arrangements for electricity and natural gas are satisfied over time, for which we record revenue based on the amount invoiced to the customer for the actual energy delivered. The performance obligation for stand-alone RECs is satisfied at a point in time, for which we record revenue when the performance obligation is satisfied upon delivery of the REC. There are no material initial incremental costs of obtaining a contract or significant financing elements in any of the arrangements.

Renewables classifies certain contracts for the sale of electricity as derivatives, in accordance with the applicable accounting standards. Renewables also has revenue from its energy trading operations, which it generally classifies as derivative revenue. However, trading contracts not classified as derivatives are within the scope of ASC 606, with the performance obligation of the delivery of energy (electricity, natural gas) and settlement of the contracts satisfied at a point in time at which time we recognize the revenue. Renewables also has other ASC 606 revenue, which we recognize based on the amount invoiced to the customer.

Certain customers may receive cash credits, which we account for as variable consideration. Renewables estimates those amounts based on the expected amount to be provided to customers and reduces revenues recognized. We believe that there will not be significant changes to our estimates of variable consideration.

Other

Other, which does not represent a segment, derives its revenues primarily from miscellaneous Corporate revenues including intersegment eliminations, and in 2018 also had revenues from providing natural gas storage services to customers, gas trading operations generally classified as derivative revenue in accordance with the applicable accounting standards and gas trading contracts not classified as derivatives.

Contract Costs, Contract Liabilities and Practical Expedient

We recognize an asset for incremental costs of obtaining a contract with a customer when we expect the benefit of those costs to be longer than one year. We have contract assets for costs from development success fees, which we paid during the solar asset development period in 2018, and will amortize ratably into expense over the 15-year life of the power purchase agreement (PPA), expected to commence in December 2021 upon commercial operation. Contract assets totaled $9 million and $12 million at December 31, 2020 and 2019, respectively, and are presented in "Other non-current assets" on our consolidated balance sheets.

We have contract liabilities for revenue from transmission congestion contract (TCC) auctions, for which we receive payment at the beginning of an auction period and amortize ratably each month into revenue over the applicable auction period. The auction periods range from six months to two years. TCC contract liabilities totaled $9 million and $10 million at December 31, 2020 and 2019, respectively, and are presented in "Other current liabilities" on our consolidated balance sheets. For both the years ended December 31, 2020 and 2019, we recognized $21 million as revenue related to contract liabilities and for the year ended December 31, 2018, we recognized $13 million.

We apply a practical expedient to expense as incurred costs to obtain a contract when the amortization period is one year or less. We record costs incurred to obtain a contract within operating expenses, including amortization of capitalized costs.

Revenues disaggregated by major source for our reportable segments for the years ended December 31, 2020, 2019 and 2018 are as follows:

	Year Ended December 31, 2020			
	Networks	**Renewables**	**Other (b)**	**Total**
(Millions)				
Regulated operations – electricity	$ 3,642	$ —	$ —	$ 3,642
Regulated operations – natural gas	1,311	—	—	1,311
Nonregulated operations – wind	—	822	—	822
Nonregulated operations – solar	—	19	—	19
Nonregulated operations – thermal	—	39	—	39
Other (a)	58	101	—	159
Revenue from contracts with customers	**5,011**	**981**	—	**5,992**
Leasing revenue	6	—	—	6
Derivative revenue	—	136	—	136
Alternative revenue programs	157	—	—	157
Other revenue	14	15	—	29
Total operating revenues	**$ 5,188**	**$ 1,132**	**$ —**	**$ 6,320**

	Year Ended December 31, 2019			
	Networks	Renewables	Other (b)	Total
(Millions)				
Regulated operations – electricity	$ 3,485	$ —	$ —	$ 3,485
Regulated operations – natural gas	1,479	—	—	1,479
Nonregulated operations – wind	—	803	—	803
Nonregulated operations – solar	—	26	—	26
Nonregulated operations – thermal	—	29	—	29
Other (a)	91	62	(12)	141
Revenue from contracts with customers	**5,055**	**920**	**(12)**	**5,963**
Leasing revenue	6	—	—	6
Derivative revenue	—	244	—	244
Alternative revenue programs	75	—	—	75
Other revenue	28	20	—	48
Total operating revenues	**$ 5,164**	**$ 1,184**	**$ (12)**	**$ 6,336**

	Year Ended December 31, 2018			
	Networks	Renewables	Other (b)	Total
(Millions)				
Regulated operations – electricity	$ 3,641	$ —	$ —	$ 3,641
Regulated operations – natural gas	1,473	—	—	1,473
Nonregulated operations – wind	—	636	—	636
Nonregulated operations – solar	—	17	—	17
Nonregulated operations – thermal	—	47	—	47
Nonregulated operations – gas storage	—	—	10	10
Other (a)	58	(68)	9	(1)
Revenue from contracts with customers	**5,172**	**632**	**19**	**5,823**
Leasing revenue	38	346	—	384
Derivative revenue	—	124	10	134
Alternative revenue programs	80	—	—	80
Other revenue	20	36	—	56
Total operating revenues	**$ 5,310**	**$ 1,138**	**$ 29**	**$ 6,477**

(a) Primarily includes certain intra-month trading activities, billing, collection and administrative charges, sundry billings and other miscellaneous revenue.
(b) Does not represent a segment. Includes Corporate, Gas (for 2018 only) and intersegment eliminations.

As of December 31, 2020 and 2019, trade receivable balances related to contracts with customers were approximately $1,151 million and $1,050 million, respectively, including $341 million and $345 million of unbilled revenue, which are included in “Accounts receivable and unbilled revenues, net” on our consolidated balance sheets.

As of December 31, 2020, the aggregate amount of the transaction price allocated to performance obligations that are unsatisfied (or partially unsatisfied) were as follows:

As of December 31, 2020	2021	2022	2023	2024	2025	Thereafter	Total
(Millions)							
Revenue expected to be recognized on multiyear retail energy sales contracts in place	$ 1	$ 1	$ 1	$ 1	$ —	$ —	$ 4
Revenue expected to be recognized on multiyear capacity and carbon-free energy sale contracts	31	23	13	4	3	5	79
Revenue expected to be recognized on multiyear renewable energy credit sale contracts	40	24	16	14	12	75	182
Total operating revenues	**$ 72**	**$ 48**	**$ 30**	**$ 19**	**$ 15**	**$ 80**	**$ 265**

We do not disclose information about remaining performance obligations for contracts for which we recognize revenue in the amount to which we have the right to invoice (e.g., usage-based pricing terms).

Note 5. Industry Regulation

Electricity and Natural Gas Distribution – Maine, New York, Connecticut and Massachusetts

Each of Networks' eight regulated utility companies must comply with regulatory procedures that differ in form but in all cases conform to the basic framework outlined below. Generally, tariff reviews cover various years and provide for a reasonable ROE, protection from, and automatic adjustments for, exceptional costs incurred and efficiency incentives. The distribution rates and allowed ROEs for Networks' regulated utilities in New York are subject to regulation by the New York Public Service Commission (NYPSC), in Maine by the Maine Public Utilities Commission (MPUC), in Connecticut by the Connecticut Public Utilities Regulatory Authority (PURA) and in Massachusetts by the Department of Public Utilities (DPU).

The revenues of Networks companies are essentially regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. The tariffs applied to the Networks companies are approved by the regulatory commissions of the different states and are based on the cost of providing service. The revenues of each of the Networks companies are set to be sufficient to cover its operating costs, including energy costs, finance costs and the costs of equity, the last of which reflects our capital ratio and a reasonable ROE.

Energy costs that are incurred in the New York and New England wholesale markets are passed on to consumers. The difference between energy costs that are budgeted and those that are actually incurred by the utilities is offset by applying compensation procedures that result in either immediate or deferred tariff adjustments. These procedures apply to other costs, which are in most cases exceptional, such as the effects of extreme weather conditions, environmental factors, regulatory and accounting changes, and treatment of vulnerable customers, that are offset in the tariff process. Any New York and Connecticut revenues that allow a utility to exceed target returns, usually the result of better than expected cost efficiency, are generally shared between the utility and its customers, resulting in future tariff reductions.

The NYSEG and RG&E rate plans, the Maine distribution rate plan and associated proceedings, the Federal Energy Regulatory Commission (FERC) Transmission Return on Equity (ROE) case, the Connecticut rate plans, Reforming Energy Vision (REV), the storm proceedings in New York and the Tax Act are some of the most important specific regulatory processes that currently affect Networks.

CMP Distribution Rate Case

In an order issued on February 19, 2020, the MPUC authorized an increase in CMP's distribution revenue requirement of $17 million, or approximately 7%, based on an allowed ROE of 9.25% and a 50% equity ratio. The rate increase was effective March 1, 2020. The MPUC also imposed a 1.00% ROE reduction (to 8.25%) for management efficiency associated with CMP's customer service performance following the implementation of its new billing system in 2017. The management efficiency adjustment will remain in effect until CMP has demonstrated satisfactory customer service performance on four specified service quality measures for a rolling average period of 18 months, which commenced on March 1, 2020. CMP is meeting the required rolling average benchmarks on all four of these quality measures.

The order provided additional funding for staffing increases, vegetation management programs and storm restoration costs, while retaining the basic tiered structure for storm cost recovery implemented in the 2014 stipulation. The MPUC order also retained the RDM implemented in 2014. The order denied CMP's request to increase rates for higher costs associated with services provided by its affiliates and ordered the initiation of a management audit to evaluate whether CMP's current management structure, and the management and other services from its affiliates, are appropriate and in the interest of Maine customers. The management audit was commenced in July 2020 by the MPUC's consultants and is expected to conclude in 2021.

CMP Revenue Decoupling Mechanism Investigation

On June 9, 2020, the MPUC issued a Notice of Investigation to open an investigation into the effects of the COVID-19 pandemic on customers' electricity-usage patterns and whether CMP's RDM should be suspended for the annual distribution rate change that is expected to occur on July 1, 2021, for electricity delivered in calendar year 2020. On June 24, 2020, the MPUC issued a procedural order setting forth initial steps in this proceeding. On July 21, 2020, CMP filed testimony presenting electricity-usage data for its two RDM classes (residential and commercial/industrial) through June 2020, along with testimony explaining the data and the reasons why the current RDM should remain in place without alteration. On August 11, 2020, a technical conference was held and CMP filed electricity-usage data on August 20, 2020. On December 16, 2020, the MPUC issued an order that retains CMP's RDM but the RDM should be simplified by merging the two RDM classes into a single class. There is no impact to existing RDM balances as a result of the order issued by the MPUC.

NYSEG and RG&E Rate Plans

2016 Joint Proposal

On June 15, 2016, the NYPSC approved NYSEG's and RG&E's 2016 Joint Proposal for a three-year rate plan for electric and gas service which balanced the varied interests of the signatory parties including but not limited to maintaining the companies' credit quality and mitigating the rate impacts to customers. The 2016 Joint Proposal reflected many customer benefits including: acceleration of the companies' natural gas leak prone main replacement programs and increased funding for electric vegetation management to provide continued safe and reliable service. The delivery rate increases for the last year of the 2016 Joint Proposal can be summarized as follows:

	May 1, 2018		
Utility		**Rate Increase (Millions)**	**Delivery Rate Increase %**
NYSEG Electric	$	30	4.10 %
NYSEG Gas	$	15	7.30 %
RG&E Electric	$	26	5.70 %
RG&E Gas	$	10	5.20 %

The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas was 9.00%. The equity ratio for each company was 48%; however, the equity ratio was set at the actual up to 50% for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increased as the ROE increased, with customers receiving 50%, 75% and 90% of earnings in rate year three (May 1, 2018 – April 30, 2019) above 9.75%, 10.25% and 10.75% ROE, respectively. The rate plans also included the implementation of a rate adjustment mechanism (RAM) designed to return or collect certain defined reconciled revenues and costs, new depreciation rates and continuation of the existing RDM for each business. The 2016 Joint Proposal reflected the recovery of deferred NYSEG Electric storm costs of approximately $262 million, of which $123 million is being amortized over ten years and the remaining $139 million is being amortized over five years. The proposal also continues reserve accounting for qualifying Major Storms ($21 million annually for NYSEG Electric and $3 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds.

The 2016 Joint Proposal maintained NYSEG's and RG&E's current electric reliability performance measures (and associated potential negative revenue adjustments for failing to meet established performance levels) which include the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI). The 2016 Joint Proposal also modified certain gas safety performance measures at the companies, including those relating to the replacement of leak prone mains, leak backlog management, emergency response and damage prevention. The proposal established threshold performance levels for designated aspects of customer service quality and continued and expanded NYSEG's and RG&E's bill reduction and arrears forgiveness Low Income Programs with increased funding levels. The 2016 Joint Proposal provided for the implementation of NYSEG's Energy Smart Community (ESC) Project in the Ithaca region which serves as a test-bed for implementation and deployment of Reforming the Energy Vision (REV) initiatives. The ESC Project is supported by NYSEG's planned Distribution Automation upgrades and Advanced Metering Infrastructure (AMI) implementation for customers on circuits in the Ithaca region. The companies also are pursuing Non-Wires Alternative projects as described in the proposal. Other REV-related incremental costs and fees were included in the RAM to the extent cost recovery is not provided for elsewhere. Under the proposal, the RAM was applicable to all customers and serves to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; (4) REV costs and fees which are not covered by other recovery mechanisms; and (5) NYSEG Electric Pole Attachment revenues. RG&E implemented a RAM in July 2018 since certain eligibility thresholds were exceeded.

The 2016 Joint Proposal provided for partial or full reconciliation of certain expenses including, but not limited to: pensions and other postretirement benefits; property taxes; variable rate debt and new fixed rate debt; gas research and development; environmental remediation costs; major storms; nuclear electric insurance limited credits; economic development; and low income programs. The 2016 Joint Proposal also included a downward-only Net Plant reconciliation. In addition, the 2016 Joint Proposal included downward-only reconciliations for the costs of electric distribution and gas vegetation management, pipeline integrity and incremental maintenance. The 2016 Joint Proposal provided that NYSEG and RG&E continue their electric RDMs on a total revenue per class basis and their gas RDMs on a revenue per customer basis.

2020 Joint Proposal

On June 22, 2020, NYSEG and RG&E filed a joint proposal with the NYPSC for a new three-year rate plan (2020 Joint Proposal). On November 19, 2020, the NYPSC approved the 2020 Joint Proposal, with modifications to the rate increases at the two electric businesses. The modifications were made to limit the overall bill impacts, to a level at or below 2% per year, in consideration of the current impacts of COVID-19 on the economic climate. The effective date of new tariffs was December 1, 2020 with a make-whole provision back to April 17, 2020. The proposed rates facilitate the companies' transition to a cleaner energy future while allowing for important initiatives such as COVID-19 relief for customers and additional funding for vegetation management, hardening/resiliency and emergency preparedness. The rate plans continue the RAM designed to return or collect certain defined reconciled revenues and costs, have new depreciation rates and continue existing RDMs for each business. The 2020 Joint Proposal bases delivery revenues on an 8.80% ROE and 48% equity ratio; however, for the proposed earnings sharing mechanism, the equity ratio is the lower of the actual equity ratio or 50%. The below table provides a summary of the approved delivery rate increases and delivery rate percentages, including rate levelization and excluding energy efficiency, which is a pass-through, for all four businesses:

	Year 1		Year 2		Year 3	
Utility	**Rate Increase (Millions)**	**Delivery Rate Increase %**	**Rate Increase (Millions)**	**Delivery Rate Increase %**	**Rate Increase (Millions)**	**Delivery Rate Increase %**
NYSEG Electric	$ 34	4.6 %	$ 46	5.9 %	$ 36	4.2 %
NYSEG Gas	$ —	— %	$ 2	0.8 %	$ 3	1.6 %
RG&E Electric	$ 17	3.8 %	$ 14	3.2 %	$ 16	3.3 %
RG&E Gas	$ —	— %	$ —	— %	$ 2	1.3 %

UI, CNG, SCG and BGC Rate Plans

Under Connecticut law, The United Illuminating Company's (UI) retail electricity customers are able to choose their electricity supplier while UI remains their electric distribution company. UI purchases power for those of its customers under standard service rates who do not choose a retail electric supplier and have a maximum demand of less than 500 kilowatts and its customers under supplier of last resort service for those who are not eligible for standard service and who do not choose to purchase electric generation service from a retail electric supplier. The cost of the power is a "pass-through" to those customers through the Generation Service Charge on their bills.

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2021, 70% of its standard service load for the second half of 2021 and 20% of its standard service load for the first half of 2022. Supplier of last resort service is procured on a quarterly basis and UI has a wholesale power supply agreement in place for the second quarter of 2021. However, from time to time, there are no bidders in the procurement process for supplier of last resort service and UI manages the load directly.

In December 2016, the PURA approved new distribution rate schedules for UI for three years, which became effective January 1, 2017 and, among other things, provide for annual tariff increases and an ROE of 9.10% based on a 50% equity ratio, continued UI's existing ESM pursuant to which UI and its customers share on a 50/50 basis all distribution earnings above the allowed ROE in a calendar year, continued the existing decoupling mechanism and approved the continuation of the requested storm reserve. Any dollars due to customers from the ESM continue to be first applied against any storm regulatory asset balance (if one exists at that time) or refunded to customers through a bill credit if such storm regulatory asset balance does not exist.

In December 2017, PURA approved new tariffs for the Southern Connecticut Gas Company (SCG) effective January 1, 2018 for a three-year rate plan with annual rate increases. The new tariffs also include an RDM and Distribution Integrity Management Program (DIMP) mechanism, ESM, the amortization of certain regulatory liabilities (most notably accumulated hardship deferral balances and certain accumulated deferred income taxes) and tariff increases based on a ROE of 9.25% and approximately 52% equity level. Any dollars due to customers from the ESM will be first applied against any environmental regulatory asset balance as defined in the settlement agreement (if one exists at that time) or refunded to customers through a bill credit if such environmental regulatory asset balance does not exist.

In December 2018, PURA approved new tariffs for Connecticut Natural Gas Corporation (CNG) effective January 1, 2019 for a three-year rate plan with annual rate increases. The new tariffs continued the RDM and DIMP mechanism, ESM and tariff increases based on an ROE of 9.30% and an equity ratio of 54% in 2019, 54.50% in 2020 and 55% in 2021.

On January 18, 2019, the DPU approved new distribution rates for BGC. The distribution rate increase is based on a 9.70% ROE and 54% equity ratio. The new tariffs provide for the implementation of an RDM and pension expense tracker and also provide that BGC will not file to change base distribution rates to become effective before November 1, 2021.

REV

In April 2014, the NYPSC commenced a proceeding entitled REV, which is a wide-ranging initiative to reform New York State’s energy industry and regulatory practices. REV has been divided into two tracks, Track 1 for Market Design and Technology, and Track 2 for Regulatory Reform. REV and its related proceedings have and will continue to propose regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar and wider deployment of distributed energy resources (DER), such as micro grids, on-site power supplies and storage.

REV is also intended to promote greater use of advanced energy management products to enhance demand elasticity and efficiencies. Track 1 of this initiative involves a collaborative process to examine the role of distribution utilities in enabling market-based deployment of DER to promote load management and greater system efficiency, including peak load reductions. NYSEG is participating in the initiative with other New York utilities. The NYPSC issued a 2015 order in Track 1, which acknowledges the utilities’ role as a Distribution System Platform provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016, followed by bi-annual updates. The companies filed the initial DSIP, which also included information regarding the potential deployment of Automated Metering Infrastructure (AMI) across its entire service territory. In December 2016, the companies filed a petition to the NYPSC requesting approval for cost recovery associated with the full deployment of AMI. A collaborative associated with this petition began in the first quarter of 2017, was suspended in the second quarter of 2017, subsequently resumed in the first quarter of 2018 and then further suspended and was been included in the companies’ May 20, 2019 rate filing. The companies also filed their first bi-annual update of the DSIP on July 31, 2018 and filed their next bi-annual update on June 30, 2020.

Other various proceedings have also been initiated by the NYPSC which are REV related, and each proceeding has its own schedule. These proceedings include the Clean Energy Standard, Value of DER and Net Energy Metering, Demand Response Tariffs and Community Choice Aggregation. As part of the Clean Energy Standard proceeding, all electric utilities were ordered to begin payments to New York State Energy Research and Development Authority (NYSERDA) for RECs and Zero Emissions Credits beginning in 2017.

Track 2 of the REV initiative is also underway, and through a NYPSC staff whitepaper review process, is examining potential changes in current regulatory, tariff, market design and incentive structures that could better align utility interests with achieving New York state and NYPSC’s policy objectives. New York utilities will also be addressing related regulatory issues in their individual rate cases. A Track 2 order was issued in May 2016, and includes guidance related to the potential for Earnings Adjustment Mechanisms (EAMs), Platform Service Revenues, innovative rate designs and data utilization and security. The companies, in December 2016, filed a proposal for the implementation of EAMs in the areas of System Efficiency, Energy Efficiency, Interconnections and Clean Air. A collaborative process to review the companies’ petition was suspended in 2017. The approved 2020 Joint Proposal includes EAMs.

In March 2017, the NYPSC issued three separate REV-related orders. These orders created a series of filing requirements for NYSEG and RG&E beginning in March 2017 and extending through the end of 2018. The three orders involve: 1) modifications to the electric utilities’ proposed interconnection EAM framework; 2) further DSIP requirements, including filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at each company by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of the Value of DER. In September 2017, the NYPSC issued another order related to the Value of DER, requiring tariff filings, changes to Standard Interconnection Requirements and planning for the implementation of automated consolidated billing. As of the end of 2018, both NYSEG and RG&E had deployed two energy storage projects each, consistent with the March 2017 NYPSC order requirements. In

December 2018, the NYPSC staff submitted whitepapers on standby and buyback service rate design, future value stack compensation and capacity value compensation. The NYPSC ruled on the proposals set forth in the whitepapers on May 16, 2019. NYSEG and RG&E filed proposed standby and buyback rates with the NYPSC in September 2019. On November 25, 2020, DPS Staff, jointly with NYSERDA, issued a whitepaper on further recommendations regarding standby and buyback rates that were based on the electric utilities' September 23, 2019 filings. Comments on the recommendations in the whitepaper are due February 22, 2021, and reply comments are due March 8, 2021.

On April 18, 2019, the NYPSC issued an order on future value stack compensation and capacity value compensation. The order established a new Community Credit in place of the Market Transition Credit for certain CDG projects in NYSEG's and RGE's territories and expanded eligibility for Phase One Net Metering for projects that have a rated capacity of 750 kW AC or lower. The changes became effective on June 1, 2019. The NYPSC also issued an order on value stack compensation for high-capacity-factor Resources on December 12, 2019, modifying the treatment of certain high-capacity-factor DER in the Value Stack compensation framework. The modification per the December 12, 2019 Order became effective February 1, 2020. On March 19, 2020, the Commission issued an additional Order regarding Value Stack Compensation. The Order directs National Grid, NYSEG and RGE to reallocate capacity from closed tranches where available capacity remained due to projects being canceled since the issuance of the VDER Compensation Order, and to assign that capacity to a new Community Credit Tranche with compensation at 2 cents per kWh. The utilities must also continue to reallocate capacity to this new Tranche for the next six months when there are cancellations of projects that have received a Market Transition Credit (MTC) or Community Credit allocation. The new provisions per the March 19, 2020 Order became effective May 1, 2020.

On May 14, 2020, the Commission issued an Order extending and expanding distributed solar incentives. In addition to authorizing the extension of and additional funding for the NY-Sun program, the Commission modified certain program rules related to the NY-Sun program and the VDER policy. As part of the ordered modifications, the Commission directed the electric utilities with VDER tariffs to add tariff language for a Remote Crediting program that will allow Value-Stack-eligible generation resources to distribute the credits they receive for generation injected into the utility system to the utility bills of multiple, separately sited, non-residential customers. The Commission ordered the utilities to submit tariff leaves that implement the modifications associated with the Remote Crediting program to become effective November 1, 2020. Given the complexity of the program changes, the utilities have petitioned the Commission for tariffs filings to be made on February 15, 2021, with an effective date of March 1, 2021.

On July 16, 2020, the Commission issued an Order establishing a net metering successor tariff. The Order continues Phase One NEM for all eligible mass market and commercial projects under 750 kW interconnected after January 1, 2022 and implements a modest customer benefit contribution (CBC) for onsite DERs to address cost recovery of certain public benefit programs. Customers that install DERs interconnected after January 1, 2022 shall be charged a monthly per kW fee based on the nameplate rating of the DER. Draft tariff leaves implementing the Commission's Order and proposed CBC calculations were filed on November 1, 2020.

On April 24, 2018, the NYPSC instituted a proceeding to consider the role of utilities in providing infrastructure and rate design to encourage the expansion electric vehicles and electric vehicle supply equipment. The Commission issued an Order on February 2, 2019 to establish a Direct Current Fast Charger incentive program, with subsequent clarifications provided in Orders issued on July 12, 2019 and March 3, 2020. On July 16, 2020, the NYPSC issued an Order on an electric vehicle make-ready program.

The make-ready program will be funded by investor-owned utilities in New York State and creates a cost-sharing program that incentivizes utilities and charging station developers to site electric vehicle charging infrastructure in places that will provide a maximal benefit to consumers.

CMP Customer Billing System Investigation

On March 1, 2018, the MPUC issued a Notice of Investigation initiating a summary investigation into CMP's metering, billing and customer communications practices. Due to the highly technical nature of CMP's customer billing system the MPUC ordered a forensic audit of CMP's customer billing system to identify any errors that have, or continue to result in billing inaccuracies, and to review CMP's customer communication practices. On December 20, 2018, the MPUC released the findings of the forensic audit of CMP's customer billing system and customer communication practices. On January 9, 2020, the hearing examiners issued their report whereby they recommended that the Commission find that the evidence in the record shows that there is no systemic problem within CMP's metering and billing systems that has caused erroneous high usage on customers' bills. Instead, the evidence-including the detailed forensic audit conducted by an independent third-party auditor-demonstrates that CMP's metering and billing systems have been, and continue to be, recording and transmitting customer usage data accurately, and, with the exception of discrete billing calculation and presentation issues, customers' billed amounts have been accurate. On January 30, 2020, the MPUC Commissioners deliberated and based on the verbal discussion, the Commissioners indicated that CMP's Metering and Billing system is accurately reporting data; there is no systemic root cause for high usage complaints and errors related to CMP’s metering and billing system are localized and random, not systemic. The Commissioners were critical of CMP finding that CMP failed to implement proper testing of the SmartCare system prior to go-live; CMP’s implementation of SmartCare was imprudent; CMP’s SmartCare implementation experienced an unacceptable number of billing errors, delayed or estimated bills, bill presentment issues and unreasonable time required to address these issues; and the implementation issues were compounded by inadequate staffing, resulting in the inability of customers to contact a CMP representative. In its February 19, 2020 order in the CMP’s distribution rate case proceeding discussed above the MPUC imposed a reduction of 100 basis points in ROE, as a management efficiency adjustment, to address concerns with CMP’s customer service performance following the implementation of its new billing system in 2017 and on February 24, 2020 issued an order in the metering and billing investigation. Each order reflected the MPUC’s conclusion that CMP’s Metering and Billing system is accurately reporting data, there is no systemic root cause for high usage complaints and errors related to CMP’s metering and billing system are localized and random, not systemic. The management efficiency adjustment will remain in effect until CMP has demonstrated satisfactory customer service performance on four specified service quality measures for a rolling average period of 18 months, which commenced on March 1, 2020. CMP is meeting the required rolling average benchmarks on all four of these quality measures. On April 27, 2020, the MPUC issued an order requiring that CMP pay for the costs of the metering, billing and customer service practices audit, which were less than $1 million.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC, MPUC, PURA, DPU and the FERC have instituted separate proceedings in New York, Maine, Connecticut, Massachusetts and the FERC, respectively, to review and address the implications of the Tax Act on the utilities.

In New York, the NYPSC issued an order requiring sur-credits to return benefits reflecting the lower effective tax rate of 21% to customers effective October 1, 2018. For NYSEG Gas, RG&E Electric and RG&E Gas the NYPSC also required the sur-credit to include the return to customers of the January - September 2018 Tax Act savings over three years. The remaining deferred amounts associated with the recognition of the effects of the Tax Act are being used as rate moderators in the approved 2020 Joint Proposal. In Connecticut, UI and SCG expect Tax Act savings to be deferred until they are reflected in tariffs in a future rate case, unless PURA determines otherwise. CNG and BGC include Tax Act savings in their current rate plans. In Maine, CMP adjusted rates beginning July 1, 2018 to pass back to customers the Tax Act savings after offsetting for recovery of deferred 2017 storm costs. In its February 19, 2020 order in the CMP’s distribution rate case proceeding discussed above, the MPUC approved CMP’s distribution related accumulated deferred income tax balances associated with the Tax Act as well as the authorized amortization periods for the return of regulatory liabilities and the recovery regulatory assets. At the FERC, CMP transmission and UI transmission adjusted their tariffs in June 2018 to reflect the income statement value of Tax Act savings.

Power Tax Audits

Previously, CMP, NYSEG and RG&E implemented Power Tax software to track and measure their respective deferred tax amounts. In connection with this change, we identified historical updates needed with deferred taxes recognized by CMP, NYSEG and RG&E and increased our deferred tax liabilities, with a corresponding increase to regulatory assets, to reflect the updated amounts calculated by the Power Tax software. Since 2015, the NYPSC and MPUC accepted certain adjustments to deferred taxes and associated regulatory assets for this item in recent distribution rate cases, resulting in regulatory asset balances of approximately $148 million and $153 million for this item at December 31, 2020 and 2019, respectively.

In 2017, audits of the power tax regulatory assets were commenced by the NYPSC and MPUC. On January 11, 2018, the NYPSC issued an order opening an operations audit on NYSEG and RG&E and certain other New York utilities regarding tax accounting. The NYPSC audit report is expected to be completed during 2021. In January 2018, the MPUC published the Power Tax audit report with respect to CMP, which indicated the auditor was unable to verify the asset “acquisition value” used to calculate the Power Tax regulatory asset. The audit report requires that CMP must provide support for the beginning balance of the regulatory assets or it will be unable to recover the value of the assets, which is approximately $11 million, excluding carrying costs. CMP responded to the audit report in its rate case filing by providing additional acquisition value support and, therefore, requested full recovery of the Power Tax regulatory asset. MPUC staff expressed concerns about the value CMP has attributed to this issue. The MPUC had an outside firm conduct an audit of CMP's filing and acquisition values, and the auditor found CMP's information was reasonable. In September 2019, CMP filed a report in response to the audit report and addressed MPUC staff concerns. On December 17, 2019, CMP filed a stipulation with the MPUC providing for recovery of the Power Tax regulatory asset and adjusting the carrying costs values for the period of July 1, 2017 through June 30, 2019. The MPUC approved the stipulation on January 21, 2020, which allowed CMP to start collecting the Power Tax Regulatory asset over the next 32.5 years beginning in July 2020.

Minimum Equity Requirements for Regulated Subsidiaries

Our regulated utility subsidiaries of Maine and New York (NYSEG, RG&E, CMP and MNG) are each subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements, each of NYSEG, RG&E, CMP and MNG must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, each utility must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. In addition, NYSEG and RG&E equity distributions that would result in a 13-month average common equity less than the maximum equity ratio utilized for the earnings sharing mechanism, or ESM, are prohibited if the credit rating of NYSEG, RG&E, AVANGRID or Iberdrola are downgraded by a nationally recognized rating agency to the lowest investment grade with a negative watch or downgraded to non-investment grade. These regulated utility subsidiaries are prohibited by regulation from lending to unregulated affiliates. These regulated utility subsidiaries have also agreed to minimum equity ratio requirements in certain borrowing agreements. These requirements are lower than the regulatory requirements.

Pursuant to agreements with the relevant utility commission, UI, SCG, CNG and BGC are restricted from paying dividends if paying such dividend would result in a common equity ratio lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. In addition, UI, SCG, CNG and BGC are prohibited from paying dividends to their parent if the utility's credit rating, as rated by any of the three major credit rating agencies, falls below investment grade, or if the utility's credit rating, as determined by two of the three major credit rating agencies, falls to the lowest investment grade and there is a negative watch or review downgrade notice.

We had restricted net assets of approximately $5,408 million associated with the minimum equity requirements as of December 31, 2020.

Movement of capital from our wholly owned unregulated subsidiaries is unrestricted.

New Renewable Source Generation

Under Connecticut Public Act (PA) 11-80, Connecticut electric utilities are required to enter into long-term contracts to purchase Connecticut Class I RECs from renewable generators located on customer premises. Under this program, UI was initially required to enter into contracts totaling approximately $200 million in commitments over an approximate 21-year period. The obligations were initially expected to phase in over a six-year solicitation period and peak at an annual commitment level of about $14 million per year after all selected projects are online. PA 17-144, PA 18-50 and PA 19-35 extended the original six-year solicitation period of the program by adding seventh, eighth, ninth, and tenth years, and increased the original funding level of this program by adding up to $64 million in additional commitments by UI. Upon purchase, UI accounts for the RECs as inventory. UI expects to partially mitigate the cost of these contracts through the resale of the RECs. PA 11-80 provides that the remaining costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

In October of 2018, UI entered into five PPAs totaling approximately 50 MW from developers of offshore wind and fuel cell generation pursuant to state law that provides the net costs of the PPAs are recoverable through electric rates. On December 19, 2018, PURA approved the PPAs, and approved UI's use of the non-bypassable federally mandated congestion charges for all customers to recover the net costs of the PPAs.

In 2019, UI entered into PPAs with 11 projects, totaling approximately 12 million MWh, pursuant to state law that provides that the net costs of the PPAs are recoverable through electric rates.

In 2020, Pursuant to Connecticut Act Concerning the Procurement of Energy Derived From Offshore Wind, UI entered into a PPA with Vineyard Wind, an affiliate of UI, to provide 804 MW of offshore wind through the development of its Park City Wind Project. Similar to the case with the zero carbon PPAs discussed above, the net costs of the PPAs are recoverable through electric rates.

Pursuant to Maine law, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or RECs, from qualifying resources. The MPUC is further authorized to order Maine transmission and distribution utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen's 60 Megawatt (MW) Rollins wind farm. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. Pursuant to a MPUC Order dated December 18, 2017, CMP entered into a 20-year agreement with Dirigo Solar, LLC on September 10, 2018, to purchase capacity and energy from multiple Dirigo solar facilities throughout CMP’s service territory. CMP’s purchase obligations under the Dirigo contract will increase as additional solar facilities are brought on line, eventually reaching a level of approximately $4 million per year. Pursuant to a MPUC Order dated November 6, 2019, CMP entered into a 20-year agreement with Maine Aqua Ventus I GP LLC on December 9, 2019, to purchase capacity and energy from an off-shore wind under development near Monhegan Island, Maine. CMP’s purchase obligations under the Maine Aqua Ventus contract will be approximately $12 million per year once the facility begins commercial operation. Pursuant to Maine law, the MPUC must conduct two competitive solicitation processes to procure, in the aggregate, an amount of energy or RECs from Class 1A resources that is equal to 14% of retail electricity sales in the State during calendar year 2018, or 1.715 million MWh. Of that 14% total, the MPUC must acquire at least 7%, but not more than 10%, through contracts approved by December 31, 2020 (Tranche 1), and acquire the remaining amount (Tranche 2) through a solicitation process that started on January 15, 2021. Pursuant to Maine law, on September 23, 2020, the MPUC issued an order accepting term sheet proposals from 14 projects in CMP's service territory and ordered the MPUC Staff and CMP to negotiate and execute contracts to implement the accepted terms. As of December 31, 2020, one project has withdrawn from the solicitation and CMP has executed contracts with 5 of the remaining 13 projects for 20-year terms. In accordance with MPUC orders, CMP either sells the purchased energy from these facilities in the ISO New England markets or periodically auctions the purchased output to wholesale buyers in the New England regional market. Under Maine law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under Maine law, and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

Connecticut Storm Reimbursement Legislation

On October 7, 2020, the Governor of Connecticut signed into law an energy bill that, among other things, instructs PURA to revise the rate-making structure in Connecticut to adopt performance-based rates for each electric distribution company, increases the maximum civil penalties assessable for failures in emergency preparedness, and provides certain penalties and reimbursements to customers after storm outages greater than 96 hours and extends rate case timelines.

Note 6. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations, our utilities capitalize as regulatory assets incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific regulatory order, we use regulatory precedent to determine if recovery is probable. Our operating utilities also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. The primary items that are not included in rate base or accruing carrying costs are regulatory assets for qualified pension and other postretirement benefits, which reflect unrecognized actuarial gains and losses; debt premium; environmental remediation costs, which are primarily the offset of accrued liabilities for future spending; unfunded future income taxes, which are the offset to the unfunded future deferred income tax liability recorded; asset retirement obligations; hedge losses; and contracts for differences. The total net amount of these items is approximately $1,484 million.

The regulatory assets and regulatory liabilities shown in the tables below result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Regulatory assets as of December 31, 2020 and 2019 consisted of:

As of December 31,	2020	2019
(Millions)		
Pension and other post-retirement benefits cost deferrals	$ 105	$ 125
Pension and other post-retirement benefits	927	1,061
Storm costs	451	272
Rate adjustment mechanism	33	79
Revenue decoupling mechanism	58	19
Transmission revenue reconciliation mechanism	31	5
Contracts for differences	86	92
Hardship programs	20	29
Plant decommissioning	3	5
Deferred purchased gas	30	25
Deferred transmission expense	26	11
Environmental remediation costs	247	277
Debt premium	83	97
Unamortized losses on reacquired debt	26	29
Unfunded future income taxes	373	399
Federal tax depreciation normalization adjustment	148	153
Asset retirement obligation	21	17
Deferred meter replacement costs	33	27
COVID-19 cost recovery	1	—
Other	180	139
Total regulatory assets	**2,882**	**2,861**
Less: current portion	310	294
Total non-current regulatory assets	**$ 2,572**	**$ 2,567**

“Pension and other post-retirement benefits” represent the actuarial losses on the pension and other post-retirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. “Pension and other post-retirement benefits cost deferrals” include the difference between actual expense for pension and other post-retirement benefits and the amount provided for in rates for certain of our regulated utilities. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

“Storm costs” for CMP, NYSEG, RG&E and UI are allowed in rates based on an estimate of the routine costs of service restoration. The companies are also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. A portion of this balance is amortized through current rates, and the remaining portion will be determined through future rate cases.

“Rate adjustment mechanism” represents an interim rate change to return or collect certain defined reconciled revenues and costs for NYSEG and RG&E following the approval of the Joint Proposal by the NYPSC. The RAM, when triggered, is implemented in rates on July 1 of each year for return or collection over a twelve-month period.

“Reliability support services” represents the difference between actual expenses for reliability support services and the amount provided for in rates.

"Revenue decoupling mechanism" represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

"Transmission revenue reconciliation mechanism" reflects differences in actual costs in the rate year from those used to set rates. This mechanism contains the Annual Transmission True up (ATU), which is recovered over the subsequent June to May period.

“Contracts for Differences” represent the deferral of unrealized gains and losses on contracts for differences derivative contracts. The balance fluctuates based upon quarterly market analysis performed on the related derivatives. The amounts, which do not earn a return, are fully offset by a corresponding derivative asset/liability.

“Hardship Programs” represent hardship customer accounts deferred for future recovery to the extent they exceed the amount in rates.

“Deferred Purchased Gas” represents the difference between actual gas costs and gas costs collected in rates.

“Deferred Transmission Expense” represents deferred transmission income or expense and fluctuates based upon actual revenues and revenue requirements.

“Environmental remediation costs” includes spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

“Debt premium” represents the regulatory asset recorded to offset the fair value adjustment to the regulatory component of the non-current debt of UIL at the acquisition date. This amount is being amortized to interest expense over the remaining term of the related outstanding debt instruments.

“Unamortized losses on reacquired debt” represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

“Unfunded future income taxes” represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment and are the offset to the unfunded future deferred income tax liability recorded. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates. These amounts are being collected over a period of forty-six years and the NYPSC staff has initiated an audit, as required, of the unfunded future income taxes and other tax assets to verify the balances.

“Federal tax depreciation normalization adjustment” represents the revenue requirement impact of the difference in the deferred income tax expense required to be recorded under the IRS normalization rules and the amount of deferred income tax expense that was included in cost of service for rate years covering 2011 forward. The recovery period in New York is from 25 to 35 years and for CMP 32.5 years beginning in 2020.

“Asset retirement obligations” represents the differences in timing of the recognition of costs associated with our AROs and the collection of such amounts through rates. This amount is being amortized at the related depreciation and accretion amounts of the underlying liability.

“Deferred meter replacement costs” represent the deferral of the book value of retired meters which were replaced or are planned to be replaced by AMI meters. This amount is being amortized over the initial depreciation period of related retired meters.

"COVID-19 cost recovery" represents deferred COVID-19-related costs in the state of Connecticut based on the order issued by PURA on April 29, 2020, requiring utilities to track COVID-19-related expenses and lost revenue and create a regulatory asset.

“Other” includes post-term amortization deferrals and various items subject to reconciliation including hedge losses and deferred property tax.

Regulatory liabilities as of December 31, 2020 and 2019 consisted of:

As of December 31,	2020	2019
(Millions)		
Energy efficiency portfolio standard	$ 58	$ 72
Gas supply charge and deferred natural gas cost	3	11
Pension and other post-retirement benefits cost deferrals	59	80
Carrying costs on deferred income tax bonus depreciation	34	49
Carrying costs on deferred income tax - Mixed Services 263(a)	11	15
2017 Tax Act	1,435	1,548
Rate change levelization	55	10
Revenue decoupling mechanism	9	17
Accrued removal obligations	1,184	1,173
Asset sale gain account	7	10
Economic development	28	27
Positive benefit adjustment	30	37
Theoretical reserve flow thru impact	10	14
Deferred property tax	31	17
Net plant reconciliation	20	23
Debt rate reconciliation	63	67
Rate refund – FERC ROE proceeding	33	32
Transmission congestion contracts	22	23
Merger-related rate credits	14	16
Accumulated deferred investment tax credits	25	13
Asset retirement obligation	18	14
Earnings sharing provisions	17	28
Middletown/Norwalk local transmission network service collections	18	18
Low income programs	28	33
Non-firm margin sharing credits	14	16
New York 2018 winter storm settlement	9	11
Other	176	149
Total regulatory liabilities	**3,411**	**3,523**
Less: current portion	274	242
Total non-current regulatory liabilities	**$ 3,137**	**$ 3,281**

“Energy efficiency portfolio standard” represents the costs of energy efficiency programs deferred for future recovery to the extent they exceed the amount in rates. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three years and began in 2020.

"Gas supply charge and deferred natural gas cost" reflects the actual costs of purchasing, transporting and storing of natural gas. Gas supply reconciliation is determined by comparing actual gas supply expenses to the monthly gas cost recoveries in rates. Prior rate year balances are collected/ returned to customers beginning the next calendar year.

“Pension and other postretirement benefits cost deferrals” include the difference between actual expense for pension and other post-retirement benefits and the amount provided for in rates for certain of our regulated utilities. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

“Carrying costs on deferred income tax bonus depreciation” represent the carrying costs benefit of increased accumulated deferred income taxes created by the change in tax law allowing bonus depreciation. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three years and began in 2020.

"Carrying costs on deferred income tax - Mixed Services 263(a)" represent the carrying costs benefit of increased accumulated deferred income taxes created by Section 263 (a) IRC. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three years and began in 2020.

“2017 Tax Act” represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC, MPUC, PURA and DPU have instituted separate proceedings in New York, Maine, Connecticut and Massachusetts, respectively, to review and address the implications associated with the Tax Act on the utilities providing service in such states.

"Rate change levelization" adjusts the New York delivery rate increases across the three-year plan to avoid unnecessary spikes and offsetting dips in customer rates. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

"Revenue decoupling mechanism" represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

“Accrued removal obligations” represent the differences between asset removal costs recorded and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

“Asset sale gain account” represents the net gain on the sale of certain assets that will be used for the future benefit of customers. The amortization period in current rates is three years for NYSEG and two years for RG&E and began in 2020.

“Economic development” represents the economic development program, which enables NYSEG and RG&E to foster economic development through attraction, expansion and retention of businesses within its service territory. If the level of actual expenditures for economic development allocated to NYSEG and RG&E varies in any rate year from the level provided for in rates, the difference is refunded to customers. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three years and began in 2020.

“Positive benefit adjustment” resulted from Iberdrola’s 2008 acquisition of AVANGRID (formerly Energy East Corporation). This is being used to moderate increases in rates. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three to five years and began in 2020.

“Theoretical reserve flow thru impact” represents the differences from the rate allowance for applicable federal and state flow through impacts related to the excess depreciation reserve amortization. It also represents the carrying cost on the differences. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three to five years and began in 2020.

"Deferred property tax" represents the difference between actual expense for property taxes recoverable from customers and the amount provided for in rates. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

"Net plant reconciliation" represents the reconciliation of the actual electric and gas net plant and book depreciation to the targets set forth in the 2020 Joint Proposal. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

"Debt rate reconciliation" represents the over/under collection of costs related to debt instruments identified in the rate case. Costs would include interest, commissions and fees versus amounts included in rates.

"Rate refund - FERC ROE proceeding" represents the reserve associated with the FERC proceeding around the base return on equity (ROE) reflected in ISO New England, Inc.’s (ISO-NE) open access transmission tariff (OATT). See Note 14 for more details.

"Transmission congestion contracts" represents deferral of the Nine Mile 2 Nuclear Plant transmission congestion contract at RGE. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

“Merger-related rate credits” resulted from the acquisition of UIL. This is being used to moderate increases in rates. In the years ended December 31, 2020 and 2019, respectively, $2 million and $2 million of rate credits were applied against customer bills.

"Earning sharing provisions" represents the annual earnings over the earning sharing threshold. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

"Middletown/Norwalk local transmission network service collections" represents allowance for funds used during construction of the Middletown/Norwalk transmission line, which is being amortized over the useful life of the project.

“Low income programs” represent various hardship and payment plan programs approved for recovery.

"New York 2018 winter storm settlement" represents the settlement amount with the NYSPSC following the comprehensive investigation of New York’s major utility companies’ preparation and response to March 2018 storms. This balance is being amortized through current rates over an amortization period of three years, beginning in 2020.

“Other” includes cost of removal being amortized through rates and various items subject to reconciliation.

Note 7. Goodwill and Intangible assets

Goodwill by reportable segment as of December 31, 2020 and 2019 consisted of:

As of December 31,	**2020**	**2019**
(Millions)		
Networks	$ 2,747	$ 2,747
Renewables	372	372
Total	**$ 3,119**	**$ 3,119**

During 2020, there were no changes in gross amounts and accumulated losses of goodwill for the Networks and Renewables reportable segments. During 2019, Renewables' goodwill was reduced by $8 million as a result of the sale of a 50% interest in the Poseidon projects described in Note 22.

Goodwill Impairment Assessment

For impairment testing purposes, our reporting units are the same as operating segments, except for Networks, which contains three reporting units, Maine, New York and UIL. Goodwill for the Maine reporting unit is $325 million from the purchase of CMP by Energy East Corporation in 2000. Goodwill for the New York reporting unit is $654 million primarily from the purchase of RG&E by Energy East in 2002. Goodwill for the UIL reporting unit is $1,768 million from the 2015 acquisition of UIL.

We perform our annual impairment testing in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our reporting units, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity specific events and events affecting a reporting unit.

Our quantitative impairment testing includes various assumptions, primarily the discount rate, and forecasted cash flows. We use a discount rate that is developed using market participant assumptions, which consider the risk and nature of the respective reporting unit’s cash flows and the rates of return market participants would require in order to invest their capital in our reporting units. We test the reasonableness of the conclusions of our quantitative impairment testing using a range of discount rates and a range of assumptions for long-term cash flows.

We had no impairment of goodwill in 2020 and 2019 as a result of our impairment testing.

Intangible assets

Intangible assets include those assets acquired in business acquisitions and intangible assets acquired and developed from external third parties and from affiliated companies. Following is a summary of intangible assets as of December 31, 2020 and 2019:

As of December 31, 2020	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Wind development	$ 593	$ (290)	$ 303
Other	31	(29)	2
Total Intangible Assets	**$ 624**	**$ (319)**	**$ 305**

As of December 31, 2019	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Wind development	$ 591	$ (289)	$ 302
Other	28	(16)	12
Total Intangible Assets	**$ 619**	**$ (305)**	**$ 314**

Wind development costs, with the exception of future 'pipeline' development costs, are amortized on a straight-line basis in accordance with the life of the related assets once placed in service. For the year ended December 31, 2020, amortization expense was for $14 million, and for both the years ended December 31, 2019 and 2018 amortization expense was $15 million. We believe our future cash flows will support the recoverability of our intangible assets.

We expect amortization expense for the five years subsequent to December 31, 2020, to be as follows:

Year ending December 31,	Amount
(Millions)	
2021	$ 14
2022	$ 13
2023	$ 12
2024	$ 12
2025	$ 12

Note 8. Property, Plant and Equipment

Property, plant and equipment as of December 31, 2020, consisted of:

As of December 31, 2020	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 16,364	$ 12,854	$ 29,218
Natural gas transportation, distribution and other	4,637	13	4,650
Other common operating property	—	274	274
Total Property, Plant and Equipment in Service	**21,001**	**13,141**	**34,142**
Total accumulated depreciation	(5,363)	(4,436)	(9,799)
Total Net Property, Plant and Equipment in Service	**15,638**	**8,705**	**24,343**
Construction work in progress	1,384	1,024	2,408
Total Property, Plant and Equipment	**$ 17,022**	**$ 9,729**	**$ 26,751**

Property, plant and equipment as of December 31, 2019, consisted of:

As of December 31, 2019	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 15,092	$ 12,360	$ 27,452
Natural gas transportation, distribution and other	4,373	13	4,386
Other common operating property	—	258	258
Total Property, Plant and Equipment in Service	**19,465**	**12,631**	**32,096**
Total accumulated depreciation	(4,968)	(4,090)	(9,058)
Total Net Property, Plant and Equipment in Service	**14,497**	**8,541**	**23,038**
Construction work in progress	1,271	887	2,158
Total Property, Plant and Equipment	**$ 15,768**	**$ 9,428**	**$ 25,196**

Capitalized interest costs were $51 million, $51 million and $26 million for the years ended December 31, 2020, 2019 and 2018, respectively. Accrued liabilities for property, plant and equipment additions were $285 million, $357 million and $154 million as of December 31, 2020, 2019 and 2018, respectively.

We impaired or wrote off amounts of $7 million, $11 million and $0 for the years ended December 31, 2020, 2019 and 2018, respectively, resulting from reassessment of the economic feasibility of our various Renewables development projects under construction.

Depreciation expense for the years ended December 31, 2020, 2019 and 2018, amounted to $973 million, $918 million and $840 million, respectively.

Note 9. Asset retirement obligations

AROs are intended to meet the costs for dismantling and restoration work that we have committed to carry out at our operational facilities.

The reconciliation of ARO carrying amounts for the years ended December 31, 2020 and 2019 consisted of:

(Millions)	
As of December 31, 2018	**$ 217**
Liabilities settled during the year	(5)
Liabilities incurred during the year	6
Accretion expense	12
Revisions in estimated cash flows (a)	(40)
As of December 31, 2019	**$ 190**
Liabilities settled during the year	(2)
Liabilities incurred during the year	9
Accretion expense	11
Revisions in estimated cash flows (a)	2
As of December 31, 2020	**$ 210**

(a) Represents a reduction in our estimate of expected cash flows required for retirement activities related to our renewable energy facilities.

Several of the wind generation facilities have restricted cash for purposes of settling AROs. As of December 31, 2020 and 2019, restricted cash related to AROs was $3 million and $2 million, respectively. These amounts have been included in “Other Assets” on our consolidated balance sheets. Accretion expenses are included in “Operations and maintenance” in our consolidated statements of income.

We have AROs for which a liability has not been recognized because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including for the removal of hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

Note 10. Debt

Long-term debt as of December 31, 2020 and 2019 consisted of:

As of December 31,		2020			2019	
	Maturity Dates	Balances		Interest Rates	Balances	Interest Rates
(Millions)						
First mortgage bonds - fixed (a)	2021-2049	$	2,575	1.85%-8.00%	$ 2,218	3.07%-8.00%
Unsecured pollution control notes - fixed	2023-2029		478	1.40%-3.50%	538	2.00%-3.50%
Term loan - variable			—		500	2.40%
Other various non-current debt - fixed	2021-2050		4,785	1.95%-7.80%	4,228	2.80%-10.48%
Unamortized debt issuance costs and discount			(47)		(38)	
Total Debt			**7,791**		**7,446**	
Less: debt due within one year, included in current liabilities			313		730	
Total Non-current Debt		**$**	**7,478**		**$ 6,716**	

(a) The first mortgage bonds have pledged collateral of substantially all the respective utility's in service properties of approximately $7,483 million.

Iberdrola Loan

On December 14, 2020, AVANGRID and Iberdrola entered into an intra-group loan agreement which provided AVANGRID with an unsecured subordinated loan in an aggregate principal amount of $3,000 million (the Iberdrola Loan).

The Iberdrola Loan bears interest (i) from December 16, 2020 until June 15, 2021, at an interest rate of 0.20%, which increases one basis point each month following the first month of the term of the Iberdrola Loan up to a maximum interest rate of 0.25%, and (ii) from June 16, 2021 until the Iberdrola Loan and any accrued and unpaid interest is repaid in its entirety, at AVANGRID's equity cost of capital as published by Bloomberg. Interest is payable on a monthly basis in arrears.

AVANGRID is required to repay the Iberdrola Loan in full upon certain equity issuances by AVANGRID in which Iberdrola participates or a change of control of AVANGRID. In addition, on or after June 15, 2021, upon five business days' notice to Iberdrola, AVANGRID may voluntarily repay the Iberdrola Loan and any accrued and unpaid interest, in whole or in part, without prepayment premium or penalty if there is a change in AVANGRID's business plan and AVANGRID determines that the Iberdrola Loan is no longer required. The intra-group loan agreement contains certain customary affirmative and negative covenants and events of default.

As of December 31, 2020, the Iberdrola Loan had no current maturities and is included in "Non-current debt with affiliate" on our consolidated balance sheet as we do not intend on repaying the Iberdrola Loan with current assets. Proceeds from the Iberdrola Loan of $1,438 million and $300 million, respectively, are included in "cash and cash equivalents" and "prepayments and other current assets" on our consolidated balance sheet as of December 31, 2020. The remainder of the proceeds reduced our commercial paper balance.

Other 2020 Long-Term Debt Issuances

Company	Issue Date	Type	Amount (Millions)		Interest rate	Maturity
AVANGRID	4/9/2020	Unsecured Notes	$	750	3.20 %	2025
NYSEG (1)	5/1/2020	Pollution Control Bonds	$	200	1.40% - 1.61%	2026 -2029
BGC	9/1/2020	Unsecured Notes	$	25	3.68 %	2050
NYSEG	9/25/2020	Unsecured Notes	$	200	1.95 %	2030
RG&E	11/23/2020	First Mortgage Bonds	$	200	1.85 %	2030
UI	12/1/2020	Unsecured Notes	$	75	2.02 %	2030
CMP	12/15/2020	First Mortgage Bonds	$	50	1.87 %	2030
CNG	12/15/2020	Unsecured Notes	$	30	2.02 %	2030
SCG	12/15/2020	First Mortgage Bonds	$	50	1.87 %	2030

(1) Non-cash remarketing of bonds to reset interest rates.

Long-term debt maturities, including sinking fund obligations, due over the next five years consist of:

2021	2022	2023	2024	2025	Total
(Millions)					
$ 313	$ 363	$ 439	$ 612	$ 1,107	$ 2,834

We make certain standard covenants to lenders in our third-party debt agreements, including, in certain agreements, covenants regarding the ratio of indebtedness to total capitalization. A breach of any covenant in the existing credit facilities or the agreements governing our other indebtedness would result in an event of default. Certain events of default may trigger automatic acceleration. Other events of default may be remedied by the borrower within a specified period or waived by the lenders and, if not remedied or waived, give the lenders the right to accelerate. Neither we nor any of our subsidiaries were in breach of covenants or of any obligation that could trigger the early redemption of our debt as of both December 31, 2020 and 2019.

Fair Value of Debt

As of December 31, 2020 and 2019, the estimated fair value of long-term debt, including the Iberdrola Loan, was $12,166 million and $8,168 million, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value of debt is considered Level 2 within the fair value hierarchy.

Short-term Debt

AVANGRID has a commercial paper program with a limit of $2 billion which is backstopped by the AVANGRID credit facilities described below.

AVANGRID had $307 million and $560 million of notes payable as of December 31, 2020 and 2019, respectively. As of December 31, 2020 and 2019, the balance consisted of $309 million and $562 million, respectively, of commercial paper, presented net of discounts on the balance sheet. As of December 31, 2020 and 2019, the weighted-average interest rate on outstanding commercial paper was 0.32% and 2.07%, respectively.

AVANGRID Credit Facility

AVANGRID and its subsidiaries, NYSEG, RG&E, CMP, UI, CNG, SCG and BGC have a revolving credit facility with a syndicate of banks, or the AVANGRID Credit Facility, that provides for maximum borrowings of up to $2,500 million in the aggregate.

Under the terms of the AVANGRID Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. On June 29, 2020, we entered into an amendment to the AVANGRID Credit Facility, which reduced AVANGRID's maximum sublimit from $2,000 million to $1,500 million and added minimum sublimits for each joint borrower other than AVANGRID. Under the AVANGRID Credit Facility, each of the borrowers pays an annual facility fee that is dependent on their credit rating. As of December 31, 2020, the facility fees ranged from 10.0 to 17.5 basis points. The AVANGRID Credit Facility matures on June 29, 2024.

2020 Credit Facility

On June 29, 2020, we entered into a revolving credit agreement with several lenders (the 2020 Credit Facility), that provides maximum borrowings up to $500 million. We pay an annual facility fee, which ranges from 15 to 30 basis points, dependent on AVANGRID’s credit rating. As of December 31, 2020, the facility fee is 20 basis points. The 2020 Credit Facility matures on June 28, 2021. We have the right to extend, and the banks are obligated to extend, the commitments and loans outstanding under the facility for one year at a cost of 75 basis points. We may also request an extension of the facility for one year, which the banks may grant at their discretion for a fee that will be determined at the time of the request. As of December 31, 2020, there were no borrowings outstanding under this credit facility.

Since our credit facilities are also a backstop to the AVANGRID commercial paper program, the amount available under the facilities as of December 31, 2020 and December 31, 2019 was $2,691 million and $1,938 million, respectively.

Iberdrola Group Credit Facility

AVANGRID has a credit facility with Iberdrola Financiacion, S.A.U., a company of the Iberdrola Group. The facility has a limit of $500 million and matures on June 18, 2023. AVANGRID pays a facility fee of 10.5 basis points annually on the facility. As of both December 31, 2020 and 2019, there was no outstanding amount under this credit facility.

Note 11. Fair Value of Financial Instruments and Fair Value Measurements

We determine the fair value of our derivative assets and liabilities and non-current equity investments associated with Networks' activities utilizing market approach valuation techniques:

- Our equity and other investments consist of Rabbi Trusts for deferred compensation plans and a supplemental retirement benefit life insurance trust. The Rabbi Trusts primarily include equity securities, fixed income and money market funds. We measure the fair value of our Rabbi Trust portfolio using observable, unadjusted quoted market prices in active markets for identical assets and include the measurements in Level 1. We measure the fair value of the supplemental retirement benefit life insurance trust based on quoted prices in the active markets for the various funds within which the assets are held and include the measurement in Level 2.
- NYSEG and RG&E enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. They hedge their electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. NYSEG and RG&E hedge approximately 70% of their electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value the companies' open electric energy derivative contracts are based on quoted prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value measurements in Level 1.
- NYSEG and RG&E enter into natural gas derivative contracts to hedge their forecasted purchases required to serve their natural gas load obligations. The forward market prices used to value open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange (NYMEX). Because we use prices quoted in an active market we include the fair value measurements in Level 1.
- NYSEG, RG&E and CMP enter into fuel derivative contracts to hedge their unleaded and diesel fuel requirements for their fleet vehicles. Exchange-based forward market prices are used, but because an unobservable basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.
- UI enters into CfDs, which are marked-to-market based on a probability-based expected cash flow analysis that is discounted at risk-free interest rates and an adjustment for non-performance risk using credit default swap rates. We include the fair value measurement for these contracts in Level 3 (See Note 12 for further discussion of CfDs).

We determine the fair value of our derivative assets and liabilities associated with Renewables activities utilizing market approach valuation techniques. Exchange-traded transactions, such as NYMEX futures contracts, that are based on quoted market prices in active markets for identical products with no adjustment are included in fair value Level 1. Contracts with delivery periods of two years or less which are traded in active markets and are valued with or derived from observable market data for identical or similar products such as over-the-counter NYMEX, foreign exchange swaps, and fixed price physical and basis and index trades are included in fair value Level 2. Contracts with delivery periods exceeding two years or that have unobservable inputs or inputs that cannot be corroborated with market data for identical or similar products are included in fair value Level 3. The unobservable inputs include historical volatilities and correlations for tolling arrangements and extrapolated values for certain power swaps. The valuation for this category is based on our judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists.

We determine the fair value of our foreign currency exchange derivative instruments based on current exchange rates compared to the rates at inception of the hedge. We include the fair value measurement for these contracts in Level 2.

The carrying amounts for cash and cash equivalents, the short-term investment from the proceeds of the Iberdrola Loan, restricted cash, accounts receivable, accounts payable, notes payable, lease obligations and interest accrued approximate their estimated fair values and are considered Level 1.

Restricted cash was $4 million and $6 million as of December 31, 2020 and 2019, respectively and is included in "Other Assets" on our consolidated balance sheets.

The financial instruments measured at fair value as of December 31, 2020 and 2019 consisted of:

As of December 31, 2020 (Millions)	Level 1	Level 2	Level 3	Netting	Total
Equity and other investments with readily determinable fair values	**$ 49**	**$ 14**	**$ —**	**$ —**	**$ 63**
Derivative assets					
Derivative financial instruments - power	$ 5	$ 31	$ 105	$ (54)	$ 87
Derivative financial instruments - gas	—	24	19	(35)	8
Contracts for differences	—	—	2	—	2
Total	**$ 5**	**$ 55**	**$ 126**	**$ (89)**	**$ 97**
Derivative liabilities					
Derivative financial instruments - power	$ (23)	$ (31)	$ (23)	$ 72	$ (5)
Derivative financial instruments - gas	(1)	(9)	(2)	9	(3)
Contracts for differences	—	—	(88)	—	(88)
Derivative financial instruments – Other	—	—	—	—	—
Total	**$ (24)**	**$ (40)**	**$ (113)**	**$ 81**	**$ (96)**

As of December 31, 2019 (Millions)	Level 1	Level 2	Level 3	Netting	Total
Equity and other investments with readily determinable fair values	**$ 38**	**$ 13**	**$ —**	**$ —**	**$ 51**
Derivative assets					
Derivative financial instruments - power	$ 4	$ 23	$ 120	$ (54)	$ 93
Derivative financial instruments - gas	—	40	31	(71)	—
Contracts for differences	—	—	2	—	2
Total	**$ 4**	**$ 63**	**$ 153**	**$ (125)**	**$ 95**
Derivative liabilities					
Derivative financial instruments - power	$ (28)	$ (43)	$ (29)	$ 92	$ (8)
Derivative financial instruments - gas	(4)	(26)	(5)	33	(2)
Contracts for differences	—	—	(94)	—	(94)
Derivative financial instruments – Other	—	(1)	—	—	(1)
Total	**$ (32)**	**$ (70)**	**$ (128)**	**$ 125**	**$ (105)**

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2020, 2019 and 2018 consisted of:

(Millions)	2020	2019	2018
Fair value as of January 1,	**$ 25**	**$ (15)**	**$ 6**
Gains for the year recognized in operating revenues	8	53	18
Losses for the year recognized in operating revenues	(2)	(2)	(9)
Total gains or losses for the period recognized in operating revenues	6	51	9
Gains recognized in OCI	1	2	—
Losses recognized in OCI	(3)	(3)	(5)
Total gains or losses recognized in OCI	(2)	(1)	(5)
Net change recognized in regulatory assets and liabilities	6	5	(5)
Purchases	(2)	(22)	(6)
Settlements	(15)	4	(10)
Transfers out of Level 3 (a)	(5)	3	(4)
Fair value as of December 31,	**$ 13**	**$ 25**	**$ (15)**
Gains for the year included in operating revenues attributable to the change in unrealized gains relating to financial instruments still held at the reporting date	$ 6	$ 51	$ 9

(a) Transfers out of Level 3 were the result of increased observability of market data.

Level 3 Fair Value Measurement

The table below illustrates the significant sources of unobservable inputs used in the fair value measurement of our Level 3 derivatives and the variability in prices for those transactions classified as Level 3 derivatives as of December 31, 2020.

Index	Avg.	Max.	Min.
NYMEX ($/MMBtu)	$ 2.53	$ 3.47	$ 1.48
AECO ($/MMBtu)	$ 1.45	$ 3.24	$ (0.17)
Ameren ($/MWh)	$ 26.12	$ 40.53	$ 14.73
COB ($/MWh)	$ 33.30	$ 95.00	$ 8.20
ComEd ($/MWh)	$ 24.10	$ 39.26	$ 12.65
ERCOT N hub ($/MWh)	$ 32.19	$ 196.95	$ 11.25
ERCOT S hub ($/MWh)	$ 32.55	$ 203.37	$ 11.41
Indiana hub ($/MWh)	$ 28.23	$ 43.58	$ 16.36
Mid C ($/MWh)	$ 29.76	$ 95.00	$ 4.00
Minn hub ($/MWh)	$ 22.82	$ 37.78	$ 11.52
NoIL hub ($/MWh)	$ 24.00	$ 39.01	$ 12.70
PJM W hub ($/MWh)	$ 28.46	$ 59.53	$ 14.28

Our Level 3 valuations primarily consist of NYMEX gas and fixed price power swaps with delivery periods extending through 2024 and 2032, respectively. The gas swaps are used to hedge merchant wind positions. The power swaps are used to hedge merchant wind production in the West and Midwest.

We considered the measurement uncertainty regarding the Level 3 gas and power positions to changes in the valuation inputs. Given the nature of the transactions in Level 3, the only material input to the valuation is the market price of gas or power for transactions with delivery periods exceeding two years. The fixed price power swaps are economic hedges of future power generation, with decreases in power prices resulting in unrealized gains and increases in power prices resulting in unrealized losses. The gas swaps are economic hedges of merchant generation, with decreases in gas prices resulting in unrealized gains and increases in gas prices resulting in unrealized losses. As all transactions are economic hedges of the underlying position, any changes in the fair value of these transactions will be offset by changes in the anticipated purchase/sales price of the underlying commodity.

Two elements of the analytical infrastructure employed in valuing transactions are the price curves used in the calculation of market value and the models themselves. We maintain and document authorized trading points and associated forward price curves, and we develop and document models used in valuation of the various products.

Transactions are valued in part on the basis of forward price, correlation and volatility curves. We maintain and document descriptions of these curves and their derivations. Forward price curves used in valuing the transactions are applied to the full duration of the transaction.

The determination of fair value of the CfDs (see Note 12 for further details on CfDs) was based on a probability-based expected cash flow analysis that was discounted at risk-free interest rates, as applicable, and an adjustment for non-performance risk using credit default swap rates. Certain management assumptions were required, including development of pricing that extends over the term of the contracts. We believe this methodology provides the most reasonable estimates of the amount of future discounted cash flows associated with the CfDs. Additionally, on a quarterly basis, we perform analytics to ensure that the fair value of the derivatives is consistent with changes, if any, in the various fair value model inputs. Significant isolated changes in the risk of non-performance, the discount rate or the contract term pricing would result in an inverse change in the fair value of the CfDs. Additional quantitative information about Level 3 fair value measurements of the CfDs is as follows:

Unobservable Input	Range at December 31, 2020
Risk of non-performance	0.50% - 0.51%
Discount rate	0.17% - 0.36%
Forward pricing ($ per KW-month)	$2.00 - $5.30

Note 12. Derivative Instruments and Hedging

Our operating and financing activities are exposed to certain risks, which are managed by using derivative instruments. All derivative instruments are recognized as either assets or liabilities at fair value on our consolidated balance sheets in accordance with the accounting requirements concerning derivative instruments and hedging activities.

(a) Networks activities

The tables below present Networks' derivative positions as of December 31, 2020 and 2019, respectively, including those subject to master netting agreements and the location of the net derivative positions on our consolidated balance sheets:

As of December 31, 2020	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Millions)				
Not designated as hedging instruments				
Derivative assets	$ 3	$ 5	$ 3	$ 3
Derivative liabilities	(3)	(4)	(34)	(78)
	—	1	(31)	(75)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(1)	—
	—	—	(1)	—
Total derivatives before offset of cash collateral	—	1	(32)	(75)
Cash collateral receivable	—	—	18	1
Total derivatives as presented in the balance sheet	$ —	$ 1	$ (14)	$ (74)

As of December 31, 2019	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Millions)				
Not designated as hedging instruments				
Derivative assets	$ 1	$ 4	$ 1	$ 2
Derivative liabilities	(1)	(2)	(39)	(86)
	—	2	(38)	(84)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(1)	(1)
	—	—	(1)	(1)
Total derivatives before offset of cash collateral	—	2	(39)	(85)
Cash collateral receivable	—	—	27	1
Total derivatives as presented in the balance sheet	$ —	$ 2	$ (12)	$ (84)

The net notional volumes of the outstanding derivative instruments associated with Networks' activities as of December 31, 2020 and 2019, respectively, consisted of:

As of December 31,	2020	2019
(Millions)		
Wholesale electricity purchase contracts (MWh)	5.6	5.1
Natural gas purchase contracts (Dth)	9.5	8.5
Fleet fuel purchase contracts (Gallons)	2.5	2.2

Derivatives not designated as hedging instruments

NYSEG and RG&E have an electric commodity charge that passes costs for the market price of electricity through rates. We use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities, in accordance with the accounting requirements concerning regulated operations.

NYSEG and RG&E have purchased gas adjustment clauses that allow us to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. NYSEG and RG&E use natural gas futures and forwards to manage fluctuations in natural gas commodity prices to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the accounting requirements for regulated operations.

The amounts for electricity hedge contracts and natural gas hedge contracts recognized in regulatory liabilities and assets as of December 31, 2020 and 2019 and amounts reclassified from regulatory assets and liabilities into income for the years ended 2020, 2019 and 2018 are as follows:

(Millions)	Loss or Gain Recognized in Regulatory Assets/Liabilities		Location of Loss (Gain) Reclassified from Regulatory Assets/Liabilities into Income	Loss (Gain) Reclassified from Regulatory Assets/Liabilities into Income	
As of				For the Year Ended December 31,	
December 31, 2020	**Electricity**	**Natural Gas**	**2020**	**Electricity**	**Natural Gas**
Regulatory assets	$ 17	$ 1	Purchased power, natural gas and fuel used	$ 55	$ 4
Regulatory liabilities	$ —	$ —			
December 31, 2019			**2019**		
Regulatory assets	$ 24	$ 4	Purchased power, natural gas and fuel used	$ 25	$ 1
Regulatory liabilities	$ —	$ —			
			2018		
			Purchased power, natural gas and fuel used	$ (10)	$ (1)

Pursuant to a PURA order, UI and Connecticut's other electric utility, CL&P, each executed two long-term CfDs with certain incremental capacity resources, each of which specifies a capacity quantity and a monthly settlement that reflects the difference between a forward market price and the contract price. The costs or benefits of each contract will be paid by or allocated to customers and will be subject to a cost-sharing agreement between UI and CL&P pursuant to which approximately 20% of the cost or benefit is borne by or allocated to UI customers and approximately 80% is borne by or allocated to CL&P customers.

PURA has determined that costs associated with these CfDs will be fully recoverable by UI and CL&P through electric rates, and UI has deferred recognition of costs (a regulatory asset) or obligations (a regulatory liability), including carrying costs. For those CfDs signed by CL&P, UI records its approximate 20% portion pursuant to the cost-sharing agreement noted above. As of December 31, 2020, UI has recorded a gross derivative asset of $2 million ($0 million of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $86 million, a gross derivative liability of $88 million ($85 million of which is related to UI's portion of the CfD signed by CL&P) and a regulatory liability of $0. As of December 31, 2019, UI has recorded a gross derivative asset of $2 million ($0 million of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $92 million, a gross derivative liability of $94 million ($92 million of which is related to UI's portion of the CfD signed by CL&P) and a regulatory liability of $0.

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets, for the years ended December 31, 2020, 2019 and 2018, respectively, were as follows:

	Years Ended December 31,		
	2020	**2019**	**2018**
(Millions)			
Derivative Assets	$ —	$ (3)	$ (6)
Derivative Liabilities	$ 6	$ 8	$ 1

Certain foreign currency exchange contracts are not designated as hedging instruments. For the year ended December 31, 2020, we recorded a gain of $4 million related to our foreign currency contracts not designated as hedging instruments, included in "Other income" in our condensed consolidated statements of income. No amounts were recorded for both the years ended December 31, 2019 and 2018.

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging relationships on OCI and income for the years ended December 31, 2020, 2019 and 2018, respectively, consisted of:

Year Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives (a)	Location of Loss Reclassified from Accumulated OCI into Income	Loss Reclassified from Accumulated OCI into Income	Total amount per Income Statement
(Millions)				
2020				
Interest rate contracts	$ —	Interest expense	$ 4	$ 316
Commodity contracts	(1)	Purchased power, natural gas and fuel used	1	1,379
Foreign currency exchange contracts	1		—	
Total	**$ —**		**$ 5**	
2019				
Interest rate contracts	$ —	Interest expense	$ 6	$ 310
Commodity contracts	—	Purchased power, natural gas and fuel used	1	1,509
Foreign currency exchange contracts	(1)		—	
Total	**$ (1)**		**$ 7**	
2018				
Interest rate contracts	$ —	Interest expense	$ 8	$ 303
Commodity contracts	(1)	Purchased power, natural gas and fuel used	—	1,653
Total	**$ (1)**		**$ 8**	

(a) Changes in accumulated OCI are reported on a pre-tax basis.

On June 20, 2019, Networks entered into a forward contract to hedge the foreign currency exchange risk of approximately $100 million in forecasted capital expenditures through June 2023. The forward foreign currency contracts are designated and qualify as cash flow hedges and are expected to be settled upon the payment to vendors for capital expenditures. The gain or loss on the foreign exchange derivative is reported as a component of accumulated OCI and will be reclassified into earnings over the useful life of the underlying capital expenditures.

The net loss in accumulated OCI related to previously settled forward starting swaps and accumulated amortization is $51 million and $55 million as of December 31, 2020 and 2019, respectively. We recorded $4 million, $6 million and $6 million in net derivative losses related to discontinued cash flow hedges during the years ended December 31, 2020, 2019 and 2018, respectively. We will amortize approximately $4 million of discontinued cash flow hedges in 2021.

Unrealized losses of $1 million on hedge derivatives are reported in OCI because the forecasted transaction is considered to be probable as of December 31, 2020. We expect that immaterial amounts of those losses will be reclassified into earnings within the next twelve months. The maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted fleet fuel transactions is twelve months.

(b) Renewables activities

The below presented quantitative information includes derivative financial instruments associated with Gas activities, which were sold during 2018.

We sell fixed-price gas and power forwards to hedge our merchant wind assets from declining commodity prices for our Renewables business. We also purchase fixed-price gas and basis swaps and sell fixed-price power in the forward market to hedge the spark spread or heat rate of our merchant thermal assets. We also enter into tolling arrangements to sell the output of our thermal generation facilities.

Renewables has proprietary trading operations that enter into fixed-price power and gas forwards in addition to basis swaps. The intent is to speculate on fixed-price commodity and basis volatility in the U.S. commodity markets.

Renewables will periodically designate derivative contracts as cash flow hedges for both its thermal and wind portfolios. The fair value changes are recorded in OCI. For thermal operations, Renewables will periodically designate both fixed price NYMEX gas contracts and natural gas basis swaps that hedge the fuel requirements of its Klamath Plant in Klamath, Oregon. Renewables will also designate fixed price power swaps at various locations in the U.S. market to hedge future power sales from its Klamath facility and various wind farms.

The net notional volumes of outstanding derivative instruments associated with Renewables' activities as of December 31, 2020 and 2019, respectively, consisted of:

As of December 31,	**2020**	**2019**
(MWh/Dth in Millions)		
Wholesale electricity purchase contracts	3	4
Wholesale electricity sales contracts	7	9
Natural gas and other fuel purchase contracts	24	29
Financial power contracts	12	10
Basis swaps - purchases	35	42
Basis swaps - sales	2	1

The fair values of derivative contracts associated with Renewables' activities as of December 31, 2020 and 2019, respectively, consisted of:

As of December 31,	**2020**	**2019**
(Millions)		
Wholesale electricity purchase contracts	$ 4	$ 10
Wholesale electricity sales contracts	11	4
Natural gas and other fuel purchase contracts	—	(2)
Financial power contracts	66	73
Basis swaps - purchases	7	—
Total	**$ 88**	**$ 85**

The tables below present Renewables' derivative positions as of December 31, 2020 and 2019, respectively, including those subject to master netting agreements and the location of the net derivative position on our consolidated balance sheets:

As of December 31, 2020	**Current Assets**	**Noncurrent Assets**	**Current Liabilities**	**Noncurrent Liabilities**
(Millions)				
Not designated as hedging instruments				
Derivative assets	$ 47	$ 89	$ 2	$ 9
Derivative liabilities	(23)	(2)	(4)	(11)
	24	87	(2)	(2)
Designated as hedging instruments				
Derivative assets	8	15	2	7
Derivative liabilities	(5)	(6)	(3)	(10)
	3	9	(1)	(3)
Total derivatives before offset of cash collateral	27	96	(3)	(5)
Cash collateral payable	(9)	(18)	—	—
Total derivatives as presented in the balance sheet	$ 18	$ 78	$ (3)	$ (5)

As of December 31, 2019	Current Assets		Noncurrent Assets		Current Liabilities		Noncurrent Liabilities	
(Millions)								
Not designated as hedging instruments								
Derivative assets	$	23	$	110	$	42	$	13
Derivative liabilities		(1)		(7)		(48)		(18)
		22		103		(6)		(5)
Designated as hedging instruments								
Derivative assets		—		18		5		4
Derivative liabilities		—		(9)		(13)		(6)
		—		9		(8)		(2)
Total derivatives before offset of cash collateral		22		112		(14)		(7)
Cash collateral (payable) receivable		(11)		(30)		7		6
Total derivatives as presented in the balance sheet	$	11	$	82	$	(7)	$	(1)

Derivatives not designated as hedging instruments

The effects of trading and non-trading derivatives associated with Renewables' activities for the year ended December 31, 2020, consisted of:

	Year Ended December 31, 2020					
	Trading		Non-trading		Total amount per income statement	
(Millions)						
Operating Revenues						
Wholesale electricity purchase contracts	$	(1)	$	—		
Wholesale electricity sales contracts		(1)		6		
Financial power contracts		2		—		
Financial and natural gas contracts		—		(13)		
Total loss included in operating revenues	$	—	$	(7)	$	6,320
Purchased power, natural gas and fuel used						
Wholesale electricity purchase contracts	$	—	$	(4)		
Financial and natural gas contracts		—		6		
Total gain included in purchased power, natural gas and fuel used	$	—	$	2	$	1,379
Total Loss	$	—	$	(5)		

(Millions)	Year Ended December 31, 2019 Trading	Non-trading	Total amount per income statement
Operating Revenues			
Wholesale electricity purchase contracts	$ (1)	$ —	
Wholesale electricity sales contracts	3	40	
Financial power contracts	(3)	23	
Financial and natural gas contracts	(1)	1	
Total (loss) gain included in operating revenues	$ (2)	$ 64	$ 6,336
Purchased power, natural gas and fuel used			
Financial power contracts	—	(1)	
Financial and natural gas contracts	—	15	
Total gain included in purchased power, natural gas and fuel used	$ —	$ 14	$ 1,509
Total (Loss) Gain	$ (2)	$ 78	

During September 2019, Renewables liquidated a portion of one of its wholesale electricity sales contracts and recorded a gain of $43 million for the year ended December 31, 2019.

The effects of trading and non-trading derivatives associated with Renewables activities for the years ended December 31, 2018 consisted of:

Years Ended December 31,	2018	
(Millions)	Trading	Non-trading
Wholesale electricity purchase contracts	$ 4	$ 11
Wholesale electricity sales contracts	(2)	(15)
Financial power contracts	—	(19)
Financial and natural gas contracts	4	—
Total Gain (Loss)	$ 6	$ (23)

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging relationships on accumulated OCI and income for the years ended December 31, 2020, 2019 and 2018 consisted of:

Year Ended December 31,	Gain (Loss) Recognized in OCI on Derivatives (a)	Location of Loss (Gain) Reclassified from Accumulated OCI into Income	Loss (Gain) Reclassified from Accumulated OCI into Income	Total amount per Income Statement
(Millions)				
2020				
Commodity contracts	$ 1	Operating revenues	$ 6	$ 6,320
2019				
Commodity contracts	$ (5)	Operating revenues	$ 3	$ 6,336
2018				
Commodity contracts	$ (11)	Operating revenues	$ (22)	$ 6,477

(a) Changes in OCI are reported on a pre-tax basis.

Amounts are reclassified from accumulated OCI into income in the period during which the transaction being hedged affects earnings or when it becomes probable that a forecasted transaction being hedged would not occur. Notwithstanding future changes in prices, approximately $3 million of gain included in accumulated OCI at December 31, 2020 is expected to be reclassified into earnings within the next twelve months. We recorded immaterial amounts of net derivative losses related to discontinued cash flow hedges for the years ended December 31, 2020, 2019 and 2018.

(c) Interest rate contracts

AVANGRID uses financial derivative instruments from time to time to alter its fixed and floating rate debt balances or to hedge fixed rates in anticipation of future fixed rate issuances.

On January 31, 2020, AVANGRID entered into two treasury locks, with a total notional amount of $600 million, to hedge the issuance of forecasted fixed rate debt. The treasury locks were designated and qualified as cash flow hedges and were settled upon the second quarter debt issuance described in Note 10. The $27 million loss on the treasury locks is reported as a component of accumulated OCI and is being reclassified into earnings during the periods in which the related interest expense of the forecasted debt is incurred.

The net loss in accumulated OCI related to previously settled interest rate contracts is $57 million and $38 million as of December 31, 2020 and 2019, respectively. We amortized into income $8 million and $2 million of the loss related to the settled interest rate contracts for the years ended December 31, 2020 and December 31, 2019, respectively. We will amortize approximately $9 million of the net loss on the interest rate contracts during 2021.

The effect of derivatives in cash flow hedging relationships on accumulated OCI for the years ended December 31, 2020 and 2019, respectively, consisted of:

Years Ended December 31,	(Loss) Recognized in OCI on Derivatives (a)	Location of Loss Reclassified from Accumulated OCI into Income	Loss Reclassified from Accumulated OCI into Income	Total amount per Income Statement
(Millions)				
2020				
Interest rate contracts	$ (27)	Interest expense	$ 8	$ 316
2019				
Interest rate contracts	$ (24)	Interest expense	$ 2	$ 310
2018				
Interest rate contracts	$ (16)	Interest expense	$ —	$ 303

(a) Changes in OCI are reported on a pre-tax basis. The amounts in accumulated OCI is being reclassified into earnings over the underlying debt maturity periods which ends in 2025 and 2029.

(d) Counterparty credit risk management

NYSEG and RG&E face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are applicable based on the respective counterparty's or the counterparty guarantor's credit rating, as provided by Moody's or Standard & Poor's. When our exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

The wholesale power supply agreements of UI contain default provisions that include required performance assurance, including certain collateral obligations, in the event that UI's credit rating on senior debt were to fall below investment grade. If such an event had occurred as of December 31, 2020, UI would have had to post an aggregate of approximately $18 million in collateral.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of a default on or termination of any single contract. For financial statement presentation purposes, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement. The amount of cash collateral under master netting arrangements that has not been offset against net derivative positions was $18 million and $21 million as of December 31, 2020 and 2019, respectively. Derivative instruments settlements and collateral payments are included throughout the "Changes in operating assets and liabilities" section of operating activities in the consolidated statements of cash flows.

Certain of our derivative instruments contain provisions that require us to maintain an investment grade credit rating on our debt from each of the major credit rating agencies. If our debt were to fall below investment grade, we would be in violation of those provisions and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit risk related contingent features that are in a liability position as of December 31, 2020 is $18 million, for which we have posted collateral.

Note 13. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation and certain buildings, vehicles and equipment. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 63 years, some of which may include options to extend the leases for up to 40 years, and some of which may include options to terminate. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost for the years ended December 31, 2020 and 2019 were as follows:

For the Year Ended December 31,	2020	2019
(Millions)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$ 17	$ 12
Interest on lease liabilities	4	3
Total finance lease cost	21	15
Operating lease cost	16	18
Short-term lease cost	3	5
Variable lease cost	—	2
Total lease cost	$ 40	$ 40

Balance sheet and other information for the years ended December 31, 2020 and 2019 was as follows:

As of December 31,	2020	2019
(Millions, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 153	$ 70
Operating lease liabilities, current	8	12
Operating lease liabilities, long-term	154	65
Total operating lease liabilities	$ 162	$ 77
Finance Leases		
Other assets	$ 162	$ 133
Other current liabilities	8	9
Other non-current liabilities	91	54
Total finance lease liabilities	$ 99	$ 63
Weighted-average Remaining Lease Term (years)		
Finance leases	8.12	7.59
Operating leases	21.38	12.98
Weighted-average Discount Rate		
Finance leases	3.71 %	5.35 %
Operating leases	3.21 %	3.62 %

For the years ended December 31, 2020 and 2019, supplemental cash flow information related to leases was as follows:

For the Year Ended December 31,		2020		2019
(Millions)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	13	$	13
Operating cash flows from finance leases	$	3	$	3
Financing cash flows from finance leases	$	9	$	27
Right-of-use assets obtained in exchange for lease obligations:				
Finance leases	$	46	$	1
Operating leases	$	94	$	3

As of December 31, 2020, maturities of lease liabilities were as follows:

		Finance Leases		Operating Leases
(Millions)				
Year ending December 31,				
2021	$	10	$	15
2022		5		15
2023		53		13
2024		23		10
2025		2		10
Thereafter		19		182
Total lease payments		112		245
Less: imputed interest		(13)		(83)
Total	$	99	$	162

Renewables has a sale-leaseback arrangement (as a seller-lessee) on a solar generation facility. The finance lease liability outstanding (including the current portion thereof) was $47 million and $50 million at December 31, 2020 and December 31, 2019, respectively. In 2013, Renewables sold the generation facility to a consortium of buyers (referred to as "Trusts") and simultaneously entered into an agreement with the Trusts for the right to use the facility for up to 15 years with an early buyout option in year 10. The gain on the sale of the generation facility was deferred and is being amortized to depreciation expense over the 25-year life of the facility.

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 14. Commitments and Contingent Liabilities

We are party to various legal disputes arising as part of our normal business activities. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. We do not provide for accrual of legal costs expected to be incurred in connection with a loss contingency.

Transmission - ROE Complaint – CMP and UI

On September 30, 2011, the Massachusetts Attorney General, DPU, PURA, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a joint complaint with the FERC, pursuant to sections 206 and 306 of the Federal Power Act, against several New England Transmission Owners (NETOs) claiming that the approved base ROE of 11.14% used by NETOs in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) was not just and reasonable and seeking a reduction of the base ROE with refunds to customers for the 15-month refund periods beginning October 1, 2011 (Complaint I), December 27, 2012 (Complaint II), July 31, 2014 (Complaint III) and April 29, 2016 (Complaint IV).

On October 16, 2014, the FERC issued its decision in Complaint I setting the base ROE at 10.57% and a maximum total ROE of 11.74% (base plus incentive ROEs) for the October 2011 – December 2012 period as well as prospectively from October 16, 2014. On March 3, 2015, the FERC upheld its decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total average transmission return. The complaints were consolidated and the administrative law judge issued an initial decision on March 22, 2016. The initial decision determined that, (1) for the fifteen month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the fifteen month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in Complaints II and III is the administrative law judge's recommendation to the FERC Commissioners.

CMP and UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 decision in Complaint I. Refunds were provided to customers for Complaint I. The CMP and UI total reserve associated with Complaints II and III is $26 million and $7 million, respectively, as of December 31, 2020, which has not changed since December 31, 2019, except for the accrual of carrying costs. If adopted as final by the FERC, the impact of the initial decision by the FERC administrative law judge would be an additional aggregate reserve for Complaints II and III of $17 million, which is based upon currently available information for these proceedings.

Following various intermediate hearings, orders and appellate decisions, on October 16, 2018, the FERC issued an order directing briefs and proposing a new methodology to calculate the NETOs ROE that is contained in NETOs' transmission formula rate on file at the FERC (the October 2018 Order).

Pursuant to the October 2018 Order, the NETOs filed initial briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019.

On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing of this decision, which was granted. On May 21, 2020, FERC issued a ruling, which, among other things, adjusted the methodology to determine the MISO transmission owners' ROE, resulting in an increase in ROE from 9.88% to 10.02% by utilizing the risk premium model in addition to the DCF model and capital-asset pricing model under both prongs of Section 206 of the FPA, and calculated the zone of reasonableness into equal thirds rather than employing the quartile approach. We cannot predict the outcome of these proceedings, including the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for our pending four Complaints.

California Energy Crisis Litigation

Two California agencies brought a complaint in 2001 against a long-term PPA entered into by Renewables, as seller, to the California Department of Water Resources, as purchaser, alleging that the terms and conditions of the PPA were unjust and unreasonable. The FERC dismissed Renewables from the proceedings; however, the Ninth Circuit Court of Appeals reversed the FERC's dismissal of Renewables from the proceeding.

Joining with two other parties, Renewables filed a petition for certiorari in the United States Supreme Court on May 3, 2007. In an order entered on June 27, 2008, the Supreme Court granted Renewables' petition for certiorari, vacated the appellate court's judgment, and remanded the case to the appellate court for further consideration in light of the Supreme Court's decision in a similar case. In light of the Supreme Court's order, on December 4, 2008, the Ninth Circuit Court of Appeals vacated its prior opinion and remanded the complaint proceedings to the FERC for further proceedings consistent with the Supreme Court's rulings. In 2014, the FERC assigned an administrative law judge to conduct evidentiary hearings. Following discovery, the FERC trial staff recommended that the complaint against Renewables be dismissed.

A hearing was held before a FERC administrative law judge in November and early December 2015. A preliminary proposed ruling by the administrative law judge was issued on April 12, 2016. The proposed ruling found no evidence that Renewables had engaged in any unlawful market conduct that would justify finding the Renewables PPAs unjust and unreasonable. However, the proposed ruling did conclude that the price of the PPAs imposed an excessive burden on customers in the amount of $259 million. Renewables position, as presented at hearings and agreed by the FERC trial staff, is that Renewables entered into bilateral power purchase contracts appropriately and complied with all applicable legal standards and requirements. The parties have submitted briefs on exceptions to the administrative law judge's proposed ruling to the FERC. There is no specific timetable for the FERC's ruling. In April 2018, Renewables requested, based on the nearly two years of delay from the preliminary proposed ruling and the Supreme Court precedent, that the FERC issue a final decision expeditiously. We cannot predict the outcome of this proceeding.

Gas Storage Indemnification Claims

On May 1, 2018, ARHI closed a transaction to sell our gas storage business to Amphora Gas Storage USA, LLC (Amphora). On October 30, 2019, ARHI received notice of a claim for indemnification from Amphora under the purchase agreement with respect to such sale in the amount of approximately $20 million related to, among other things, certain alleged violations of occupational, health and safety requirements, the condition and sufficiency of assets and a third party intellectual property infringement claim. In December 2020, ARHI and Amphora reached a settlement agreement to resolve the claim with ARHI paying Amphora $5 million and Amphora releasing ARHI and AVANGRID of all claims related to the 2018 sale of our gas business.

New York State Public Service Commission Show Cause Order Regarding Greenlight Pole Attachments

On November 20, 2020, the NYPSC issued an Order Instituting Proceeding and to Show Cause (the Show Cause Order) regarding alleged violations of the NYPSC's 2004 Order Adopting Policy Statement on Pole Attachments, dated August 6, 2004 (the 2004 Pole Order) by RG&E, Greenlight Networks, Inc, (Greenlight), and Frontier Communications (Frontier). The alleged violations detailed in the Show Cause Order arise from Greenlight's installation of unauthorized and substandard communications attachments throughout RG&E's and Frontier's service territories. The Show Cause Order directs RG&E to show cause within 30 days why the NYPSC should not pursue civil and/or administrative penalties or initiate a prudency proceeding or civil action for injunctive relief for more than 11,000 alleged violations of the 2004 Pole Order. Under NY Public Service Law Section 25-a, each alleged violation carries a potential penalty of up to $100,000 where it can be shown that the violator failed to "reasonably comply" with a statute or NYPSC order.

RG&E, Greenlight and Frontier filed respective notices to initiate settlement negotiations with respect to the alleged violations and to extend the deadline for filing a response to the Show Cause Order. The NYPSC granted the extension requests initiating settlement discussions. We cannot predict the outcome of this matter.

Power, Gas and Other Arrangements

Power and Gas Supply Arrangements – Networks

NYSEG and RG&E are the providers of last resort for customers. As a result, the companies buy physical energy and capacity from the NYISO. In accordance with the NYPSC's February 26, 2008 Order, NYSEG and RG&E are required to hedge on behalf of non-demand billed customers. The physical electric capacity purchases we make from parties other than the NYISO are to comply with the hedge requirement for electric capacity. The companies enter into financial swaps to comply with the hedge requirement for physical electric energy purchases. Other purchases, from some Independent Power Producers (IPPs) and the New York Power Authority, are from contracts entered into many years ago when the companies made purchases under contract as part of their supply portfolio to meet their load requirement. More recent IPP purchases are required to comply with the companies' Public Utility Regulatory Policies Act (PURPA) purchase obligation.

NYSEG, RG&E, SCG, CNG and BGC (collectively, the Regulated Gas Companies) satisfy their natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The Regulated Gas Companies operate diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual gas costs incurred by each of the Regulated Gas Companies are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

The Regulated Gas Companies purchase the majority of their natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. The Regulated Gas Companies diversify their sources of supply by amount purchased and location and primarily acquire gas at various locations in the U.S. Gulf of Mexico region, in the Appalachia region and in Canada.

The Regulated Gas Companies acquire firm transportation capacity on interstate pipelines under long-term contracts and utilize that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system.

The Regulated Gas Companies acquire firm underground natural gas storage capacity using long-term contracts and fill the storage facilities with gas in the summer months for subsequent withdrawal in the winter months.

Winter peaking resources are primarily attached to the local distribution systems and are either owned or are contracted for by the Regulated Gas Companies, each of which is a Local Distribution Company. Each Regulated Gas Company owns or has rights to the natural gas stored in an LNG facility directly attached to its distribution system.

Other arrangements include contractual obligations for property, plant and equipment, material and services on order but not yet delivered at December 31, 2020.

Power, Gas and Other Arrangements – Renewables

Gas purchase commitments consist of firm transport capacity to fuel the Cogen and Peaking gas generators. Power purchase commitments include the following: (i) a 55 MW Biomass PPA for 12 years (one year remaining) with a guaranteed output of 34.4 MW flat and a schedule of fixed price rates depending on season and time of day, (ii) long-term firm transmission agreements with fixed monthly capacity payments that allow the delivery of electricity from wind and thermal generation sources to various customers and (iii) a 95.6 MW (average) three-year purchase of hydro capacity and energy to provide balancing services to the NW wind assets that has monthly fixed payments (beginning in 2019 and expiring in 2021) and (iv) a five-year purchase of 52 MW (average) hydro capacity and energy to provide balancing services to the NW wind assets that has monthly fixed payments (beginning in 2019 and expiring in 2023). Power sales commitments include: (i) a 55 MW Biomass off-take agreement for 12 years (one year remaining) with guaranteed annual production of 34.4 MW flat with a schedule of fixed price rates depending on season and time of day, (ii) a retail renewable power sales agreement for 12 MW (average) expiring in 2026, (iii) fixed price, fixed volume power sales off the Klamath Cogen facility, (iv) a seasonal tolling arrangement off the Klamath peaking facility with fixed capacity charges through 2024; (v) fixed price, fixed volume renewable energy credit sales off merchant wind facilities, (vi) sales of merchant wind farm capacity to various ISOs and sales of ancillary services (e.g., regulation and frequency response, generator imbalance, etc.) to third parties from Renewables' Balancing Authority.

In June 2020, Renewables entered into a Payment In Lieu of Taxes (PILOT) agreement related to two of its projects with Torrance County, New Mexico. The agreement requires PILOT payments to Torrance County through 2049. No payments are due until 2021.

Renewables also has easement contracts which are included in the table below.

Forward purchases and sales commitments under power, gas and other arrangements as of December 31, 2020 consisted of:

Year	Purchases	Sales
	(Millions)	
2021	$ 889	$ 178
2022	135	103
2023	74	68
2024	48	41
2025	45	32
Thereafter	934	54
Totals	**$ 2,125**	**$ 476**

Guarantee Commitments to Third Parties

As of December 31, 2020, we had approximately $678 million of standby letters of credit, surety bonds, guarantees and indemnifications outstanding, including approximately $88 million related to Vineyard Wind. These instruments provide financial assurance to the business and trading partners of AVANGRID and its subsidiaries in their normal course of business. The instruments only represent liabilities if AVANGRID or its subsidiaries fail to deliver on contractual obligations. We therefore believe it is unlikely that any material liabilities associated with these instruments will be incurred and, accordingly, as of December 31, 2020, neither we nor our subsidiaries have any liabilities recorded for these instruments.

Note 15. Environmental Liabilities

Environmental laws, regulations and compliance programs may occasionally require changes in our operations and facilities and may increase the cost of electric and natural gas service. We do not provide for accruals of legal costs expected to be incurred in connection with loss contingencies.

Waste sites

The Environmental Protection Agency and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at twenty-six waste sites, which do not include sites where gas was manufactured in the past. Sixteen of the twenty-six sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites; five sites are included in Maine's Uncontrolled Sites Program; one site is included in the Brownfield Cleanup Program and one site is included on the Massachusetts Non-Priority Confirmed Disposal Site list. The remaining sites are not included in any registry list. Finally, six of the twenty-six sites are also included on the National Priorities list. Any liability may be joint and several for certain sites.

We have recorded an estimated liability of $6 million related to twelve of the twenty-six sites. We have paid remediation costs related to the remaining fourteen sites and do not expect to incur additional liabilities. Additionally, we have recorded an estimated liability of $9 million related to another twelve sites where we believe it is probable that we will incur remediation and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties or that we are regulated under State Resource Conservation and Recovery Act programs. It is possible the ultimate cost to remediate these sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $13 million to $21 million as of December 31, 2020. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the allocation of the clean-up costs.

Manufactured Gas Plants

We have a program to investigate and perform necessary remediation at our fifty-three sites where gas was manufactured in the past (Manufactured Gas Plants, or MGPs). Six sites are included in the New York State Registry; three sites are included in the New York State Department of Environmental Conservation Multi-Site Order on Consent; three sites are part of Maine's Voluntary Response Action Program with two such sites part of Maine's Uncontrolled Sites Program and one site is pending application into the Brownfield Cleanup Program. The remaining sites are not included in any registry list. We have entered into consent orders with various environmental agencies to investigate and, where necessary, remediate forty-one of the fifty-three sites.

Our estimate for all costs related to investigation and remediation of the fifty-three sites ranges from $177 million to $294 million as of December 31, 2020. Our estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial actions, changes in technology relating to remedial alternatives and changes to current laws and regulations.

Certain of our Connecticut and Massachusetts regulated gas companies own or have previously owned properties where MGPs had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. Each of the companies has or had an ownership interest in one or more such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded related to these sites as of December 31, 2020 and no amount of loss, if any, can be reasonably estimated at this time. In the past, the companies have received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

As of December 31, 2020 and 2019, the liability associated with our MGP sites in Connecticut was $96 million and $97 million, respectively, the remediation costs of which could be significant and will be subject to a review by PURA as to whether these costs are recoverable in rates.

Our total recorded liability to investigate and perform remediation at all known inactive MGP sites discussed above and other sites was $300 million and $349 million as of December 31, 2020 and 2019, respectively. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from FirstEnergy, as described below, because we expect to recover the net costs in rates. Our environmental liability accruals are recorded on an undiscounted basis and are expected to be paid through the year 2056.

FirstEnergy

NYSEG sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act to recover environmental cleanup costs at sixteen former MGP sites, which are included in the discussion above. In July 2011, the District Court issued a decision and order in NYSEG's favor, requiring FirstEnergy to pay NYSEG approximately $60 million for past and future clean-up costs at the sixteen sites in dispute. On September 9, 2011, FirstEnergy paid NYSEG $30 million, representing their share of past costs of $27 million and pre-judgment interest of $3 million.

FirstEnergy appealed the decision to the Second Circuit Court of Appeals. On September 11, 2014, the Second Circuit Court of Appeals affirmed the District Court's decision in NYSEG's favor, but modified the decision for nine sites, reducing NYSEG's damages for incurred costs from $27 million to $22 million, excluding interest, and reducing FirstEnergy's allocable share of future costs at these sites. NYSEG refunded FirstEnergy the excess $5 million in November 2014.

FirstEnergy remains liable for a substantial share of clean up expenses at nine MGP sites. Based on current projections, FirstEnergy's share is estimated at approximately $19 million. This amount is being treated as a contingent asset and has not been recorded as either a receivable or a decrease to the environmental provision. Any recovery will be flowed through to NYSEG customers.

English Station

In January 2012, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then owners of a former generation site on the Mill River in New Haven (English Station) that UI sold to Quinnipiac Energy in 2000, filed a lawsuit in federal district court in Connecticut related to environmental remediation at the English Station site. This proceeding was stayed in 2014 pending resolutions of other proceedings before the DEEP concerning the English Station site. In December 2016, the court administratively closed the file without prejudice to reopen upon the filing of a motion to reopen by any party.

In December 2013, Evergreen Power and Asnat filed a subsequent lawsuit related to the English Station site. On April 16, 2018, the plaintiffs filed a revised complaint alleging fraud and unjust enrichment against UIL and UI and adding former UIL officers as named defendants alleging fraud. On February 21, 2019, the court granted our Motion to Strike with respect to all counts except for the count against UI for unjust enrichment. The counts stricken include all counts against the individual defendants as well as against UIL. The plaintiffs have appealed the court's decision to strike and oral arguments have taken place. We cannot predict the outcome of this matter.

On April 8, 2013, DEEP issued an administrative order addressed to UI, Evergreen Power, Asnat and others, ordering the parties to take certain actions related to investigating and remediating the English Station site. This proceeding was stayed while DEEP and UI continue to work through the remediation process pursuant to the consent order described below. Status reports are periodically filed with DEEP.

On August 4, 2016, DEEP issued a partial consent order (the consent order), that, subject to its terms and conditions, requires UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. Under the consent order, to the extent that the cost of this investigation and remediation is less than $30 million, UI will remit to the State of Connecticut the difference between such cost and $30 million to be used for a public purpose as determined in the discretion of the Governor of the State of Connecticut, the Attorney General of the State of Connecticut and the Commissioner of DEEP. UI is obligated to comply with the terms of the consent order even if the cost of such compliance exceeds $30 million. Under the terms of the consent order, the state will discuss options with UI on recovering or funding any cost above $30 million such as through public funding or recovery from third parties; however, it is not bound to agree to or support any means of recovery or funding. UI has initiated its process to investigate and remediate the environmental conditions within the perimeter of the English Station site pursuant to the consent order.

As of December 31, 2020 and 2019, the amount reserved for this matter was $22 million and $16 million, respectively. We cannot predict the outcome of this matter.

On April 24, 2020, ACV Environmental Services Company (ACV) filed a lawsuit in Connecticut Superior Court against UI arising out of a contract dispute for services rendered by ACV in the demolition of the Station B at the English Station site. The complaint seeks damages in the amount of $5 million on claims of breach of contract, breach of the covenant of good faith and fair dealing, quantum merit, and unjust enrichment. The claims arise from the alleged non-payment of certain change order requests. The parties have agreed to attempt to mediate this matter during the first half of 2021. We cannot predict the outcome of this matter.

Note 16. Income Taxes

Upon enactment of the Tax Act, the Company remeasured its existing deferred income tax balances as of December 31, 2017 to reflect the decrease in the corporate income tax rate from 35% to 21%, which resulted in a material decrease to its net deferred income tax liability balances based on reasonable estimates that could be determined at that time. The Company’s non-regulatory businesses recorded a corresponding net increase or decrease to income tax expense, while the utility operations recorded corresponding regulatory liabilities or assets to the extent that such amounts are probable of settlement or recovery through customer rates. The amount and timing of potential settlements of the established net regulatory liabilities are determined by the regulated utilities’ respective rate regulators and IRS Normalization rules. As of December 31, 2018, the Company has completed the measurement and accounting of certain effects of the Tax Act which have been reflected in the consolidated financial statements.

On December 20, 2019, the Setting Every Community up for Retirement Enhancement Act of 2019, was signed into law that extended the PTC and ITC options for wind facilities to 60% of the full credit for facilities commencing construction in 2020, leaving in place phased down credits for projects commencing in years prior to 2020.

The 2020 Consolidated Appropriations Act provides extensions to renewable income tax incentives. Onshore and offshore wind projects may now claim a 60% PTC for projects commencing construction in 2020 and 2021. In addition, offshore wind may now elect to claim a 30% ITC for projects commencing construction through 2025. Onshore wind can claim an 18% ITC for projects commencing construction in 2020 or 2021, with no ITC thereafter.

Solar projects commencing construction before 2020 may claim a 30% ITC. Solar projects that commence construction from 2020-2022 may claim a 26% ITC, projects commencing construction in 2023 may claim a 22% ITC and projects commencing thereafter may claim a 10% ITC. The ITC statutes require solar projects be completed by the end of 2025 in order to claim the applicable ITCs.

The Internal Revenue Service (IRS) provided continuity safe harbor guidance that requires renewable projects to be completed within four years of the year construction commences. Any projects that do not meet this requirement will fall outside of the safe harbor and be subject to IRS scrutiny with regard to the date construction commenced. In 2020, the IRS allowed projects beginning construction in 2016 or 2017 an additional year (five years total) to complete construction. In late December 2020, the IRS issued a notice giving onshore wind projects on federal lands, with transmission permit requirements, and offshore wind projects 10 years to complete construction.

During 2020, we received orders to begin returning to customer both protected and unprotected excess ADIT from the 2017 Tax Act. Such amounts are subject to terms of the various state regulators in which we do business while meeting the requirements of normalization for both ARAM and RSG methodologies. We have accounted for those jurisdictions which have issued orders to unit operations. However, not all unit operations have been issued orders as of 2020.

Current and deferred taxes charged to expense for the years ended December 31, 2020, 2019 and 2018 consisted of:

Years Ended December 31,	**2020**	**2019**	**2018**
(Millions)			
Current			
Federal	$ 3	$ 11	$ 17
State	9	(6)	2
Current taxes charged to expense	**12**	**5**	**19**
Deferred			
Federal	67	164	231
State	38	58	(13)
Deferred taxes charged to expense	**105**	**222**	**218**
Production tax credits	(87)	(57)	(68)
Investment tax credits	(1)	(1)	(2)
Total Income Tax Expense	**$ 29**	**$ 169**	**$ 167**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2020, 2019 and 2018 consisted of:

Years Ended December 31,	**2020**	**2019**	**2018**
(Millions)			
Tax expense at federal statutory rate	$ 119	$ 170	$ 159
Depreciation and amortization not normalized	(13)	(23)	(5)
Investment tax credit amortization	(1)	(1)	(2)
Tax return related adjustments	1	(2)	(6)
Production tax credits	(87)	(57)	(68)
Tax equity financing arrangements	1	8	—
Federal tax rate impact on held for sale classification	—	—	21
State tax expense (benefit), net of federal benefit	37	41	(9)
Excess ADIT amortization	(42)	—	—
Tax Act - remeasurement	—	—	46
Other, net	14	33	31
Total Income Tax Expense	**$ 29**	**$ 169**	**$ 167**

Deferred tax assets and liabilities as of December 31, 2020 and 2019 consisted of:

As of December 31,	2020	2019
(Millions)		
Deferred Income Tax Liabilities (Assets)		
Property related	$ 4,147	$ 4,007
Unfunded future income taxes	100	101
Federal and state tax credits	(731)	(632)
Federal and state NOL's	(1,047)	(981)
Joint ventures/partnerships	167	136
Nontaxable grant revenue	(311)	(335)
Pension and other post-retirement benefits	22	43
Tax Act - tax on regulatory remeasurement	(382)	(409)
Valuation allowance	81	48
Other	(127)	(141)
Deferred Income Tax Liabilities	**$ 1,919**	**$ 1,837**
Deferred tax assets	$ 2,598	$ 2,498
Deferred tax liabilities	4,517	4,335
Net Accumulated Deferred Income Tax Liabilities	**$ 1,919**	**$ 1,837**

As of December 31, 2020, we had gross federal tax net operating losses of $3.8 billion, federal PTCs and ITCs, federal R&D tax credits and other federal credits of $695 million, state tax effected net operating losses of $324 million in several jurisdictions and miscellaneous state tax credits of $142 million available to carry forward and reduce future income tax liabilities. For federal purposes, we recognized a valuation allowance of $16 million, and for state purposes, we recognized a valuation allowance of $65 million. The federal net operating losses begin to expire in 2028, while the federal tax credits begin to expire in 2023. The more significant state net operating losses begin to expire in 2021.

Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that all or a portion of a tax benefit will not be realized. The valuation allowance for deferred tax assets as of December 31, 2020 and 2019 was $81 million and $48 million, respectively. Valuation allowances have been established on various federal tax credits, state net operating losses and state tax credit carryforwards. The Company has recorded a federal valuation allowance on its federal tax credit carryforwards of $16 million and has recorded a state valuation allowance on its state net operating losses and state tax credit carryforwards of $65 million. The $33 million increase in valuation allowance from 2019 to 2020 includes an increase of $12 million for additional valuation allowance on Federal tax credit carryforwards and an increase of $21 million on state net operating losses and state tax credits.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2020, 2019 and 2018 consisted of:

Years ended December 31,	2020	2019	2018
(Millions)			
Beginning Balance	$ 148	$ 153	$ 45
Increases for tax positions related to prior years	11	14	111
Increases for tax positions related to current year	—	16	—
Decreases for tax positions related to prior years	(32)	(18)	(3)
Reduction for tax position related to settlements with taxing authorities	—	(17)	—
Ending Balance	**$ 127**	**$ 148**	**$ 153**

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the consolidated financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized when it is more likely than not based on the technical merits the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

Accruals for interest and penalties on tax reserves were immaterial for the years ended December 31, 2020, 2019 and 2018. If recognized, $107 million of the total gross unrecognized tax benefits would affect the effective tax rate.

It is estimated that no unrecognized tax benefits are anticipated to result in a net increase or decrease within twelve months of December 31, 2020.

AVANGRID and its subsidiaries, without ARHI, have been audited for the federal tax years 1998 through 2009. The results of these audits, net of reserves already provided, were immaterial. Tax years 2010 and forward are open for potential federal adjustments. All New York state returns, which were filed without ARHI, are closed through 2011 and Maine state returns are closed through 2015.

All federal tax returns filed by ARHI from the periods ended March 31, 2004, to December 31, 2009, are closed for adjustment. All New York combined state returns are closed for adjustment through 2011. Generally, the adjustment period for the individual states we filed in is at least as long as the federal period.

As of December 31, 2020, UIL is subject to audit of its federal tax return for years 2014 through its short period 2015. UIL's short period ending in 2015 is open and subject to Connecticut audit.

Note 17. Post-retirement and Similar Obligations

AVANGRID and its subsidiaries sponsor a number of retirement benefit plans. The plans include qualified defined benefit pension plans, supplemental non-qualified pension plans, defined contribution plans and other postretirement benefit plans for eligible employees and retirees. Eligibility and benefits vary depending on each plan's design. For example, certain benefits are based on years of service and final average compensation while others may use a cash balance formula that calculates benefits using a percentage of annual compensation.

Qualified Retirement Benefit Plans

As of December 31, 2020 and 2019, our obligations and funded status consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2020**	**2019**	**2020**	**2019**
(Millions)				
Change in benefit obligation				
Benefit Obligation as of January 1,	**$ 3,669**	**$ 3,374**	**$ 439**	**$ 425**
Service cost	47	41	3	3
Interest cost	107	130	13	16
Plan amendments	7	(2)	—	—
Actuarial loss	236	347	29	26
Curtailments	(21)	—	—	—
Benefits paid	(226)	(221)	(32)	(31)
Benefit Obligation as of December 31,	**3,819**	**3,669**	**452**	**439**
Change in plan assets				
Fair Value of Plan Assets as of January 1,	**2,848**	**2,544**	**155**	**148**
Actual return on plan assets	388	460	26	22
Employer contributions	84	65	18	16
Curtailments	(2)	—	—	—
Benefits paid	(226)	(221)	(32)	(31)
Fair Value of Plan Assets as of December 31,	**3,092**	**2,848**	**167**	**155**
Funded Status as of December 31,	**$ (727)**	**$ (821)**	**$ (285)**	**$ (284)**

During 2020, the pension benefit obligation had an actuarial loss of $236 million, primarily due to a $276 million loss from decreases in discount rates. The only significant plan change in 2020 was an agreement to freeze the UI union pension plan. There were no significant gains or losses relating to the postretirement benefit obligations.

During 2019, the pension benefit obligation had an actuarial loss of $347 million, primarily due to a $384 million loss from decreases in discount rates. There were no significant plan design changes in 2019. There were no significant gains or losses relating to the postretirement benefit obligations.

As of December 31, 2020 and 2019, funded status amounts recognized on our consolidated balance sheets consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2020**	**2019**	**2020**	**2019**
(Millions)				
Current liabilities	$ —	$ —	$ (5)	$ (5)
Non-current liabilities	(727)	(821)	(280)	(279)
Total	**$ (727)**	**$ (821)**	**$ (285)**	**$ (284)**

We have determined that Networks' regulated operating companies are allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in accumulated OCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as a component of regulatory assets or regulatory liabilities for Networks for the years ended December 31, 2020 and 2019 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2020**	**2019**	**2020**	**2019**
(Millions)				
Net loss	$ 610	$ 706	$ 14	$ 13
Prior service cost (credit)	$ 10	$ 4	$ (8)	$ (21)

Amounts recognized in OCI for ARHI for the years ended December 31, 2020 and 2019, consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2020**	**2019**	**2020**	**2019**
(Millions)				
Net loss (gain)	$ 21	$ 23	$ (7)	$ (8)

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $3,629 million and $3,451 million as of December 31, 2020 and 2019, respectively.

As of December 31, 2020 and 2019, the projected benefit obligation (PBO) and the ABO exceeded the fair value of pension plan assets for all of our qualified plans, and the aggregate PBO and ABO and the fair value of plan assets for our underfunded qualified plans consisted of:

	PBO in excess of plan assets	
As of December 31,	**2020**	**2019**
(Millions)		
Projected benefit obligation	$ 3,819	$ 3,669
Fair value of plan assets	$ 3,092	$ 2,848

	ABO in excess of plan assets	
As of December 31,	**2020**	**2019**
(Millions)		
Accumulated benefit obligation	$ 3,629	$ 3,451
Fair value of plan assets	$ 3,092	$ 2,848

As of December 31, 2020 and 2019, the accumulated postretirement benefits obligation for all qualified plans exceeded the fair value of plan assets.

Components of Networks' net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2020, 2019 and 2018 consisted of:

For the years ended December 31,	Pension Benefits 2020	Pension Benefits 2019	Pension Benefits 2018	Postretirement Benefits 2020	Postretirement Benefits 2019	Postretirement Benefits 2018
(Millions)						
Net Periodic Benefit Cost:						
Service cost	$ 46	$ 41	$ 44	$ 3	$ 3	$ 4
Interest cost	106	128	126	13	16	18
Expected return on plan assets	(198)	(190)	(199)	(8)	(7)	(8)
Amortization of prior service cost (benefit)	1	(1)	1	(9)	(10)	(9)
Amortization of net loss	124	113	149	2	1	6
Net Periodic Benefit Cost	**79**	**91**	**121**	**1**	**3**	**11**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:						
Curtailments	(18)	—	—	—	—	—
Net loss (gain)	46	80	175	11	13	(37)
Amortization of net loss	(124)	(113)	(149)	(2)	(1)	(6)
Current year prior service cost (credit)	7	(2)	—	—	—	(3)
Amortization of prior service (cost) benefit	(1)	1	(1)	9	10	9
Total Other Changes	**(90)**	**(34)**	**25**	**18**	**22**	**(37)**
Total Recognized	**$ (11)**	**$ 57**	**$ 146**	**$ 19**	**$ 25**	**$ (26)**

Components of ARHI's net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and OCI for the years ended December 31, 2020, 2019 and 2018 consisted of:

For the years ended December 31,	Pension Benefits 2020	Pension Benefits 2019	Pension Benefits 2018	Postretirement Benefits 2020	Postretirement Benefits 2019	Postretirement Benefits 2018
(Millions)						
Net Periodic Benefit Cost:						
Service cost	$ 1	$ 1	$ —	$ —	$ —	$ —
Interest cost	1	2	2	—	—	1
Expected return on plan assets	(2)	(2)	(2)	—	—	—
Amortization of net loss (gain)	2	1	1	(1)	(1)	—
Settlement charge	1	—	1	—	—	—
Net Periodic Benefit Cost	**3**	**2**	**2**	**(1)**	**(1)**	**1**
Other Changes in plan assets and benefit obligations recognized in OCI:						
Net loss (gain)	1	—	1	—	—	(3)
Amortization of net (loss) gain	(2)	(1)	(1)	1	1	—
Amortization of prior service cost	—	—	—	—	(2)	—
Total Other Changes	**(1)**	**(1)**	**—**	**1**	**(1)**	**(3)**
Total Recognized	**$ 2**	**$ 1**	**$ 2**	**$ —**	**$ (2)**	**$ (2)**

The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents. We include the service cost component in other operating expenses net of capitalized portion and include the components of net periodic benefit cost other than the service cost component in other expense.

The weighted-average assumptions used to determine our benefit obligations as of December 31, 2020 and 2019 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2020**	**2019**	**2020**	**2019**
Discount rate	2.34 %	3.01 %	2.19 %	2.99 %
Rate of compensation increase	3.52 %	3.66 %	3.50 %	3.48 %
Interest crediting rate	2.87 %	2.87 %	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rates by developing yield curves derived from a portfolio of high grade noncallable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine our net periodic benefit cost for the years ended December 31, 2020, 2019 and 2018 consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	**2020**	**2019**	**2018**	**2020**	**2019**	**2018**
Discount rate	3.01 %	3.98 %	3.68 %	2.99 %	3.97 %	3.67 %
Expected long-term return on plan assets	7.30 %	7.30 %	7.30 %	5.09 %	5.08 %	5.08 %
Rate of compensation increase	3.66 %	3.79 %	3.85 %	3.48 %	3.50 %	3.50 %

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets discussed below. Our analysis considered current capital market conditions and projected conditions. NYSEG, RG&E and UIL amortize unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the NYPSC, PURA and DPU. Our other companies use the standard amortization methodology under which amounts in excess of ten-percent of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2020 and 2019 consisted of:

As of December 31,	**2020**	**2019**
Health care cost trend rate assumed for next year	5.25%/7.25%	6.75%/7.75%
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate	2029 / 2025	2029 / 2027

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. We expect to contribute $75 million and $17 million, respectively, to our pension and other postretirement benefit plans during 2021.

Estimated Future Benefit Payments

Expected benefit payments as of December 31, 2020 consisted of:

(Millions)	**Pension Benefits**	**Postretirement Benefits**
2021	$ 211	$ 31
2022	$ 224	$ 30
2023	$ 217	$ 29
2024	$ 219	$ 29
2025	$ 474	$ 49
2026 - 2030	$ 765	$ 100

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other current and Other non-current liabilities on our consolidated balance sheets, was $59 million and $56 million at December 31, 2020 and 2019, respectively.

Plan Assets

Our pension benefits plan assets are consolidated in one master trust. A consolidated trust provides for a uniform investment manager lineup and an efficient, cost effective means of allocating expenses and investment performance to each plan. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trusts' investments while avoiding significant concentrations of risk in any one area of the securities markets. Further diversification is achieved within each asset group through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. Networks and ARHI have established target asset allocation policies within allowable ranges for their pension benefits plan assets within broad categories of asset classes made up of Return-Seeking investments and Liability-Hedging investments. Networks currently has target allocations ranging from 35%-70% for Return-Seeking assets and 34%-65% for Liability-Hedging assets. ARHI currently has a target allocation of 60% for Return-Seeking assets and 40% for Liability-Hedging assets. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2020, consisted of:

As of December 31, 2020		**Fair Value Measurements**		
(Millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 120	$ —	$ 120	$ —
U.S. government securities	177	177	—	—
Common stocks	107	107	—	—
Registered investment companies	301	301	—	—
Corporate bonds	710	—	710	—
Preferred stocks	1	1	—	—
Common collective trusts	1,018	—	1,018	—
Other, principally annuity, fixed income	50	6	44	—
	$ 2,484	$ 592	$ 1,892	$ —
Other investments measured at net asset value	608			
Total	**$ 3,092**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2019, consisted of:

As of December 31, 2019		**Fair Value Measurements**		
(Millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 42	$ —	$ 42	$ —
U.S. government securities	87	87	—	—
Registered investment companies	464	464	—	—
Corporate bonds	458	—	458	—
Preferred stocks	1	1	—	—
Common collective trusts	572	—	572	—
Other, principally annuity, fixed income	84	—	84	—
	$ 1,708	$ 552	$ 1,156	$ —
Other investments measured at net asset value	1,140			
Total	**$ 2,848**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities – at the closing price reported in the active market in which the security is traded.
- Common stocks – at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts/Registered investment companies – Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2 - the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 37% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

Networks has established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 45%-65% for equity securities, 25%-45% for fixed income and 5%-25% for all other investment types. ARHI's asset allocation policy has a target allocation of 45% in equity securities, 50% in fixed income and 5% for cash and cash equivalents investments. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2020 consisted of:

As of December 31, 2020		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 6	$ —	$ 6	$ —
U.S. government securities	1	1	—	—
Registered investment companies	141	141	—	—
Corporate bonds	3	—	3	—
Common collective trusts	4	—	4	—
Other, principally annuity, fixed income	9	—	9	—
	$ 164	$ 142	$ 22	$ —
Other investments measured at net asset value	3			
Total	**$ 167**			

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2019 consisted of:

As of December 31, 2019		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 31	$ —	$ 31	$ —
Common stocks	16	16	—	—
Registered investment companies	98	98	—	—
Corporate bonds	2	—	2	—
Other, principally annuity, fixed income	8	—	8	—
Total	**$ 155**	**$ 114**	**$ 41**	**$ —**

Valuation Techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities – at the closing price reported in the active market in which the security is traded.
- Common stocks and registered investment companies – at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common collective trusts – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension and postretirement benefit plan equity securities did not include any Iberdrola common stock as of both December 31, 2020 and 2019.

Defined contribution plans

We also have defined contribution plans defined as 401(k)s for all eligible AVANGRID employees. There are various match formulas depending on years of service, age and pension plan closure/freeze date. For the years ended December 31, 2020, 2019 and 2018, the annual contributions we made to these plans was $49 million, $40 million and $37 million, respectively.

Note 18. Equity

As of December 31, 2020 and 2019, we had 413,782 and 485,810 shares of common stock held in trust, respectively, and no convertible preferred shares outstanding. During the years ended December 31, 2020 and 2019, we issued 42,777 and 0 shares of common stock, respectively, and released 72,028 and 0 shares of common stock held in trust, respectively, each having a par value of $0.01. During January 2021, we released 292,594 shares of common stock held in trust.

We maintain a repurchase agreement with J.P. Morgan Securities, LLC. (JPM), pursuant to which JPM will, from time to time, acquire, on behalf of AVANGRID, shares of common stock of AVANGRID. The purpose of the stock repurchase program is to allow AVANGRID to maintain Iberdrola's relative ownership percentage at 81.5%. The stock repurchase program may be suspended or discontinued at any time upon notice. In May 2020, 42,777 shares were repurchased pursuant to the stock repurchase program. As of December 31, 2020, a total of 303,835 shares have been repurchased in the open market, all of which are included as AVANGRID treasury shares. As of December 31, 2020, the total cost of all repurchases, including commissions, was $14 million.

Accumulated OCI (Loss)

Accumulated OCI (Loss) for the years ended December 31, 2020, 2019 and 2018 consisted of:

Accumulated Other Comprehensive Income (Loss)	As of December 31, 2017	Adoption of new accounting standard	2018 Change	As of December 31, 2018	Adoption of new accounting standard	2019 Change	As of December 31, 2019	2020 Change	As of December 31, 2020
(Millions)									
Change in revaluation of defined benefit plans, net of income tax expense (benefit) of $1 for 2018, $0 for 2019 and $0 for 2020	$ (14)	$ —	$ 3	$ (11)	$ (2)	$ 1	$ (12)	$ —	$ (12)
Loss (gain) for nonqualified pension plans, net of income tax expense (benefit) of $0 for 2018, $(1) for 2019 and $3 for 2020	(6)	(1)	1	(6)	—	(1)	(7)	(13)	(20)
Unrealized (loss) gain on derivatives qualifying as cash flow hedges:									
Unrealized loss during period on derivatives qualifying as cash flow hedges, net of income tax expense (benefit) of $(7) for 2018, $(9) for 2019 and $(7) for 2020	30	—	(21)	9	—	(22)	(13)	(22)	(35)
Reclassification to net income of losses (gains) on cash flow hedges, net of income tax expense (benefit) of $(7) for 2018, $3 for 2019 and $2 for 2020 (a)	(56)	—	(8)	(64)	(10)	11	(63)	19	(44)
Loss on derivatives qualifying as cash flow hedges	(26)	—	(29)	(55)	(10)	(11)	(76)	(3)	(79)
Accumulated Other Comprehensive Loss	**$ (46)**	**$ (1)**	**$ (25)**	**$ (72)**	**$ (12)**	**$ (11)**	**$ (95)**	**$ (16)**	**$ (111)**

(a) Reclassification is reflected in the operating expenses and interest expense, net of capitalization line items in our consolidated statements of income.

Note 19. Earnings Per Share

Basic earnings per share is computed by dividing net income attributable to AVANGRID by the weighted-average number of shares of our common stock outstanding.

The calculations of basic and diluted earnings per share attributable to AVANGRID for the years ended December 31, 2020, 2019 and 2018, respectively, consisted of:

Years Ended December 31,	2020	2019	2018
(Millions, except for number of shares and per share data)			
Numerator:			
Net income attributable to AVANGRID	$ 581	$ 667	$ 587
Denominator:			
Weighted average number of shares outstanding - basic	309,494,939	309,491,082	309,503,319
Weighted average number of shares outstanding - diluted	309,559,387	309,514,910	309,712,628
Earnings per share attributable to AVANGRID			
Earnings Per Common Share, Basic	$ 1.88	$ 2.16	$ 1.90
Earnings Per Common Share, Diluted	$ 1.88	$ 2.16	$ 1.89

Note 20. Variable Interest Entities

We participate in certain partnership arrangements that qualify as VIEs. Consolidated VIE's consist of tax equity financing arrangements (TEFs) and partnerships in which an investor holds a noncontrolling interest and does not have substantive kick-out or participating rights.

The sale of a membership interest in the TEFs represents the sale of an equity interest in a structure that is considered a sale of non-financial assets. Under the sale of non-financial assets, the membership interests in the TEFs we sell to third-party investors are reflected as noncontrolling interest on our consolidated balance sheets valued based on an HLBV model. Earnings from the TEFs are recognized in net income attributable to noncontrolling interests in our consolidated statements of income. We consolidate the entities that have TEFs based on being the primary beneficiary for these VIEs.

On March 2, 2020, we closed on two TEF agreements, receiving $237 million from two tax equity investors related to two wind farms that reached commercial operation. On May 8, 2020, we closed on a TEF agreement, receiving $70 million from the same tax equity investors related to a wind farm that reached commercial operation. The three wind farms are part of a portfolio of companies called Aeolus Wind Power VII, LLC (Aeolus VII). On February 5, 2021, we closed on the final TEF agreement for Aeolus VII in a non-cash transaction. The four Aeolus VII wind farms total 688 MW of wind power.

As of December 31, 2020, the assets and liabilities of the VIEs totaled approximately $1,713 million and $107 million, respectively. As of December 31, 2019, the assets and liabilities of VIEs totaled approximately $806 million and $29 million, respectively. At both December 31, 2020 and 2019, the assets and liabilities of the VIEs consisted primarily of property, plant and equipment.

Wind power generation is subject to certain favorable tax treatments in the U.S. In order to monetize the tax benefits, we have entered into these structured institutional partnership investment transactions related to certain wind farms. Under these structures, we contribute certain wind assets, relating both to existing wind farms and wind farms that are being placed into operation at the time of the relevant transaction, and other parties invest in the share equity of the limited liability holding company. As consideration for their investment, the third parties make either an upfront cash payment or a combination of upfront cash and payments over time. We retain a class of membership interest and day-to-day operational and management control, subject to investor approval of certain major decisions. The third-party investors do not receive a lien on any assets and have no recourse against us for their upfront cash payments.

The partnerships generally involve disproportionate allocations of profit or loss, cash distributions and tax benefits resulting from the wind farm energy generation between the investor and sponsor until the investor recovers its investment and achieves a cumulative annual after-tax return. Once this target return is met, the relative sharing of profit or loss, cash distributions and taxable income or loss between the Company and the third party investor flips, with the sponsor generally receiving higher percentages thereafter. We also have a call option to acquire the third party investors' membership interest within a defined time period after this target return is met.

At December 31, 2020, El Cabo Wind, LLC (El Cabo), Patriot Wind Farm LLC (Patriot) and Aeolus VII are our consolidated VIEs.

Our El Cabo, Patriot and Aeolus VII interests are not subject to any rights of investors that may restrict our ability to access or use the assets or to settle any existing liabilities associated with the interests.

See Note 22 - Equity Method Investments for information on our VIE we do not consolidate.

Note 21. Grants, Government Incentives and Deferred Income

The changes in deferred income as of December 31, 2020 and 2019 consisted of:

(Millions)	Government grants	Other deferred income	Total
As of December 31, 2018	**$ 1,367**	**$ 18**	**$ 1,385**
Disposals	(3)	—	(3)
Derecognition due to sale (a)	(38)	—	(38)
Recognized in income	(68)	(2)	(70)
As of December 31, 2019	**1,258**	**16**	**1,274**
Disposals	(2)	—	(2)
Recognized in income	(66)	(2)	(68)
As of December 31, 2020	**$ 1,190**	**$ 14**	**$ 1,204**

(a) Grants no longer controlled by us due to the 2019 sale of a 50% interest in the Poseidon projects. See Note 22 for further information.

Within deferred income, we classify grants we received under Section 1603 of the American Recovery and Reinvestment Act of 2009, where the United States Department of Treasury (DOT) provides eligible parties the option of claiming grants for specified energy property in lieu of tax credits, which we claimed for the majority of our qualifying properties. Deferred income has been recorded for the grant amounts and is amortized as an offset against depreciation expense using the straight-line method over the estimated useful life of the associated property to which the grants apply. We recognize a net deferred tax asset for the book to tax basis differences related to the property for income tax purposes within the nontaxable grant revenue deferred income tax liabilities (see Note 16 – Income Taxes).

We are required to comply with certain terms and conditions applicable to each grant and, if a disqualifying event should occur as specified in the grant's terms and conditions, we are required to repay the grant funds to the DOT. We believe we are in compliance with each grant's terms and conditions as of December 31, 2020 and 2019.

Note 22. Equity Method Investments

On December 16, 2020, Renewables sold an 85% ownership interest in a wind farm located in South Dakota (Tatanka) to WEC Infrastructure involving total consideration of $238 million, excluding closing costs, and recognized a gain of $12 million, net of tax. The pre-tax gain of $16 million is included in "Other income (expense)" in our consolidated statements of income. Our retained investment in Tatanka of $24 million was valued based on an enterprise value of $298 million and applying an effective percentage of economic benefits retained of 7.97%, which was derived from a DCF model similar to the model used for Goodwill as described in Note 7. The net gain includes $4 million related to the remeasurement of our retained investment in Tatanka. The transaction was accounted for as a sale of assets and resulted in a loss of control. The retained 15% ownership interest is accounted for as an equity method investment. As of December 31, 2020, the carrying value of our Tatanka investment was $24 million.

On December 13, 2019, Renewables transferred a 50% ownership interest in a wind farm and a solar project located in Arizona (Poseidon) to Axium involving total consideration of $112 million, excluding closing costs, and recognized a gain of $96 million, net of tax. The pre-tax gain of $134 million is included in "Other income (expense)" in our consolidated statements of income. The net gain includes $50 million related to the remeasurement of our retained investment in Poseidon which was valued based on the consideration received in the transaction. The transaction was accounted for as the sale of a business and resulted in a loss of control. The retained 50% ownership interest is accounted for as an equity method investment. As of December 31, 2020 and 2019, the carrying value of our Poseidon investment was $104 million and $111 million, respectively.

In December 2018, Renewables sold 80% of our wholly owned subsidiary, Coyote Ridge Wind, LLC (Coyote Ridge), including substantially all of the related tax benefits, to WEC Infrastructure in exchange for $144 million of total proceeds with $84 million received in 2019 to complete the transaction. We recorded a gain of $4 million and $10 million from this transaction in "Other expense" in our consolidated statements of income for the years ended December 31, 2019 and 2018, respectively. We account for the remaining 20% membership interest under the equity method of accounting. As of December 31, 2020 and 2019, the carrying amount of our Coyote Ridge investment was $16 million and $14 million, respectively.

Renewables has two 50-50 joint ventures with Horizon Wind Energy, LLC, which own and operate the Flat Rock Windpower LLC (Flat Rock I) and the Flat Rock Wind Power II LLC (Flat Rock II) wind farms located in upstate New York. Flat Rock I has a 231 MW capacity and Flat Rock II has a 91 MW capacity. We account for the Flat Rock joint ventures under the equity method of accounting. As of December 31, 2020 and 2019, the carrying amount of Flat Rock I was $98 million and $105 million, respectively, and Flat Rock II was $47 million and $49 million, respectively.

Renewables holds a 50% voting interest in Vineyard Wind, LLC (Vineyard Wind), a joint venture with Copenhagen Infrastructure Partners (CIP). Vineyard Wind has acquired two easements from the U.S. Bureau of Ocean Energy Management (BOEM) containing the rights to develop offshore wind generation. In total, the two lease areas have the potential to generate up to 5,000 MW of renewable energy. The first easement area is 166,886 acres located southeast of Martha's Vineyard. In 2018, Vineyard Wind was selected by the Massachusetts Electric Distribution Companies (EDCs) to construct and operate Vineyard Wind's proposed 800 MW wind farm and electricity transmission project pursuant to the Massachusetts Green Communities Act Section 83C RFP for offshore wind energy projects. In December 2019, DEEP selected Vineyard Wind to provide 804 MW of offshore wind through the development of its Park City Wind Project. Pursuant to a joint bidding agreement between Renewables and CIP, CIP held a right to sell all or a portion of its 50% ownership interest to Renewables, subject to certain conditions, which expired on September 30, 2020.

During 2019, Vineyard Wind acquired a second offshore easement contract from BOEM. Renewables initially contributed $100 million to Vineyard Wind to acquire the easement contract, which was proportionally more than CIP's contribution. Pursuant to a joint bidding agreement between Renewables and CIP, CIP had the option to reimburse Renewables an amount, plus interest, to restore its 50% interest in the easement contract. In December 2020, CIP exercised this option and will reimburse Renewables $33 million, plus interest.

As of December 31, 2020, under the provisions of the LLC agreement, Renewables has contributed $252 million to Vineyard Wind, net of reimbursement by CIP. We expect to provide additional capital contributions.

In October 2020, Vineyard Wind submitted an offshore wind solicitation to NYSERDA. Renewables and CIP entered into a joint bidding agreement pursuant to which, subject to the satisfaction of certain conditions, CIP may exercise an option to effectuate a series of transactions that include the sale of its ownership interest in the Liberty Wind and Park City Wind Projects to Renewables and the purchase of Renewables' residual ownership interest in certain lease areas that have not been awarded an offtake agreement as of the date of the exercise of such option by CIP. On January 14, 2021, the options held by CIP related to Liberty Wind expired as the project was not selected by NYSERDA.

Vineyard Wind is considered a VIE because it cannot finance its activities without additional support from its owners or third-parties. Renewables is not the primary beneficiary since it does not have a controlling interest in Vineyard Wind, and therefore we do not consolidate Vineyard Wind. As of December 31, 2020 and 2019, the carrying amount of Renewables' investment in Vineyard Wind was $245 million and $227 million, respectively.

Networks is a party to a 50-50 joint venture with Clearway Energy, Inc. in GenConn, which operates two peaking generation plants in Connecticut. The investment in GenConn is accounted for as an equity investment. As of December 31, 2020 and 2019, the carrying value of our GenConn investment was $104 million and $113 million, respectively.

Networks holds an approximate 20% ownership interest in New York TransCo. Through New York TransCo, Networks has formed a partnership with Central Hudson Gas and Electric Corporation, Consolidated Edison, Inc., National Grid, plc and Orange and Rockland Utilities, Inc. to develop a portfolio of interconnected transmission lines and substations to fulfill the objectives of the New York energy highway initiative, which is a proposal to install up to 3,200 MW of new electric generation and transmission capacity in order to deliver more power generated from upstate New York power plants to downstate New York. On April 8, 2019, New York Transco was selected as the developer for Segment B of the AC Transmission Public Policy Project by the NYISO. The selected project, New York Energy Solution (NYES), replaces nearly 80-year old transmission assets located in the upper to mid-Hudson Valley with streamlined, modernized technology, to enable surplus clean energy resources in upstate New York and help achieve the State's energy goals. The total project cost is $600 million plus interconnection costs. NYSEG's contribution as 20% co-owner is $120 million. New York Transco is subject to regulatory approval of its rates, terms and conditions with the FERC. As of December 31, 2020 and 2019, the amount receivable from New York TransCo was $0 and $1 million, respectively. The investment in New York TransCo is accounted for as an equity investment. As of December 31, 2020 and 2019, the carrying value of our New York TransCo investment was $30 million and $26 million, respectively.

None of our joint ventures have any contingent liabilities or capital commitments. Distributions received from equity method investments amounted to $22 million, $17 million and $18 million for the years ended December 31, 2020, 2019 and 2018 respectively, which are reflected as either distributions of earnings or as returns of capital in the operating and investing sections of the consolidated statements of cash flows, respectively. In addition, during the years ended December 31, 2020 and 2019, we received $14 million and $9 million of distributions in RECs from our equity method investments. As of December 31, 2020, there was an immaterial amount of undistributed earnings from our equity method investments. Capitalized interest costs related to equity method investments were $8 million and $7 million for the years ended December 31, 2020 and 2019, respectively.

Note 23. Other Financial Statements Items

Loss from assets held for sale

In connection with the 2018 sale of our gas trading and storage businesses, we recorded a loss from held for sale measurement of $16 million for the year ended December 31, 2018, which is included in "Loss from assets held for sale" in our consolidated statements of income.

Other income (expense)

Other income (expense) for the years ended December 31, 2020, 2019 and 2018 consisted of:

Years ended December 31,	2020	2019	2018
(Millions)			
Gain on sale of assets (a)	$ 20	$ 148	$ 10
Allowance for funds used during construction	56	46	30
Carrying costs on regulatory assets	28	21	21
Non-service component of net periodic benefit cost	(62)	(79)	(128)
Other	(24)	(15)	1
Total Other Income (Expense)	**$ 18**	**$ 121**	**$ (66)**

(a) 2020 includes a $16 million gain from the Tatanka sale, 2019 includes a $134 million gain from the Poseidon sale and 2018 includes a $10 million gain from the Coyote Ridge sale (see Note 22).

Accounts receivable and unbilled revenues, net

Accounts receivable and unbilled revenues, net as of December 31, 2020 and 2019 consisted of:

As of December 31,	2020	2019
(Millions)		
Trade receivables and unbilled revenues	$ 1,295	$ 1,151
Allowance for credit losses	(108)	(69)
Total Accounts receivable and unbilled revenues, net	**$ 1,187**	**$ 1,082**

The change in the allowance for credit losses as of December 31, 2020 and 2019 consisted of:

(Millions)	
As of December 31, 2017	**$ 64**
Current period provision	74
Write-off as uncollectible	(76)
As of December 31, 2018	**$ 62**
Current period provision	92
Write-off as uncollectible	(85)
As of December 31, 2019	**$ 69**
Current period provision	83
Write-off as uncollectible	(44)
As of December 31, 2020	**$ 108**

DPA receivable balances were $78 million and $65 million as of December 31, 2020 and 2019, respectively.

Prepayments and Other Current Assets

Prepayments and other current assets as of December 31, 2020 and 2019 consisted of:

As of December 31,	2020	2019
(Millions)		
Prepaid other taxes	$ 135	$ 123
Short-term investment (a)	300	—
Broker margin and collateral accounts	30	33
Other pledged deposits	2	3
Prepaid expenses	41	34
Other	17	6
Total	**$ 525**	**$ 199**

(a) Short-term investment from proceeds of the Iberdrola Loan.

Other current liabilities

Other current liabilities as of December 31, 2020 and 2019 consisted of:

As of December 31,	**2020**	**2019**
(Millions)		
Advances received	$ 141	$ 143
Accrued salaries	109	89
Short-term environmental provisions	49	40
Collateral deposits received	42	44
Pension and other postretirement	5	5
Finance leases	8	9
Other	14	6
Total	**$ 368**	**$ 336**

Note 24. Segment Information

Our segment reporting structure uses our management reporting structure as its foundation to reflect how AVANGRID manages the business internally and is organized by type of business. We report our financial performance based on the following two reportable segments:

- Networks: includes all of the energy transmission and distribution activities, any other regulated activity originating in New York and Maine and regulated electric distribution, electric transmission and gas distribution activities originating in Connecticut and Massachusetts. The Networks reportable segment includes eight rate regulated operating segments. These operating segments generally offer the same services distributed in similar fashions, have the same types of customers, have similar long-term economic characteristics and are subject to similar regulatory requirements, allowing these operations to be aggregated into one reportable segment.
- Renewables: activities relating to renewable energy, mainly wind energy generation and trading related with such activities.

The chief operating decision maker evaluates segment performance based on segment adjusted net income defined as net income adjusted to exclude restructuring charges, mark-to-market earnings from changes in the fair value of derivative instruments, loss from held for sale measurement, accelerated depreciation derived from repowering of wind farms, impact of the Tax Act, costs incurred related to the PNMR Merger, costs incurred in connection with the COVID-19 pandemic and adjustments for the non-core Gas storage business.

Products and services are sold between reportable segments and affiliate companies at cost. Segment income, expense and assets presented in the accompanying tables include all intercompany transactions that are eliminated in our consolidated financial statements. Refer to Note 4 - Revenue for more detailed information on revenue by segment.

The segment information as of and for the years ended December 31, 2019 and 2018 has been revised consistent with the immaterial corrections to prior periods disclosed in Note 2, including a correction of $24 million of income tax expense at the Renewables segment for the year ended December 31, 2019 from the as reported amount of $4 million.

Segment information as of and for the year ended December 31, 2020 consisted of:

For the year ended December 31, 2020	Networks	Renewables	Other(a)	AVANGRID Consolidated
(Millions)				
Revenue - external	$ 5,187	$ 1,132	$ 1	$ 6,320
Revenue - intersegment	1	—	(1)	—
Depreciation and amortization	592	394	1	987
Operating income	877	(16)	8	869
Earnings (losses) from equity method investments	10	(13)	—	(3)
Interest expense, net of capitalization	234	7	75	316
Income tax expense (benefit)	120	(80)	(11)	29
Capital expenditures	1,838	943	—	2,781
Adjusted net income	568	115	(58)	625
As of December 31, 2020				
Property, plant and equipment	17,079	9,662	10	26,751
Equity method investments	134	534	—	668
Total assets	$ 24,592	$ 12,867	$ 364	$ 37,823

(a) Includes Corporate and intersegment eliminations.

Segment information as of and for the year ended December 31, 2019 consisted of:

For the year ended December 31, 2019	Networks	Renewables	Other(a)	AVANGRID Consolidated
(Millions)				
Revenue - external	$ 5,150	$ 1,184	$ 2	$ 6,336
Revenue - intersegment	14	—	(14)	—
Depreciation and amortization	549	383	1	933
Operating income	890	93	15	998
Earnings (losses) from equity method investments	11	(8)	—	3
Interest expense, net of capitalization	269	14	27	310
Income tax expense (benefit)	152	28	(11)	169
Capital expenditures	1,610	1,122	3	2,735
Adjusted net income	465	193	(17)	640
As of December 31, 2019				
Property, plant and equipment	15,829	9,357	10	25,196
Equity method investments	139	506	—	645
Total assets	$ 23,239	$ 13,152	$ (1,997)	$ 34,394

(a) Includes Corporate and intersegment eliminations.

Segment information for the year ended December 31, 2018 consisted of:

For the year ended December 31, 2018	Networks	Renewables	Other (a)	AVANGRID Consolidated
(Millions)				
Revenue - external	$ 5,304	$ 1,136	$ 37	$ 6,477
Revenue - intersegment	6	2	(8)	—
Loss from assets held for sale	—	—	16	16
Depreciation and amortization	503	352	—	855
Operating income	968	132	16	1,116
Earnings (losses) from equity method investments	13	(3)	—	10
Interest expense, net of capitalization	260	33	10	303
Income tax expense (benefit)	167	(32)	32	167
Capital expenditures	1,370	407	—	1,777
Adjusted net income	$ 481	$ 182	$ 13	$ 676

(a) Includes Corporate, Gas and intersegment eliminations.

Reconciliation of Adjusted Net Income to Net Income attributable to AVANGRID for the years ended December 31, 2020, 2019 and 2018 is as follows:

Years Ended December 31,	2020	2019	2018
(Millions)			
Adjusted Net Income Attributable to Avangrid, Inc.	**$ 625**	**$ 640**	**$ 676**
Adjustments:			
Restructuring charges (1)	(6)	(6)	(4)
Mark-to-market adjustments - Renewables (2)	(5)	76	(25)
Loss from held for sale measurement (3)	—	—	(16)
Impact of the Tax Act (4)	—	—	(46)
Accelerated depreciation from repowering (5)	(9)	(33)	(3)
Impact of COVID-19 (6)	(29)	—	—
Merger costs (7)	(6)	—	—
Legal settlement - Gas storage (8)	(5)	—	—
Income tax impact of adjustments	16	(10)	(6)
Gas Storage, net of tax (8)	—	—	11
Net Income Attributable to Avangrid, Inc.	**$ 581**	**$ 667**	**$ 587**

(1) Restructuring and severance related charges relate to costs resulted from restructuring actions involving initial targeted voluntary workforce reductions and related costs in our plan to vacate a lease, predominantly within the Networks segment and costs to implement an initiative to mitigate costs and achieve sustainable growth (See Note 27 - Restructuring and Severance Related Expenses – for further details).
(2) Mark-to-market earnings relates to earnings impacts from changes in the fair value of Renewables' derivative instruments associated with electricity and natural gas.
(3) Represents loss from measurement of assets and liabilities held for sale in connection with the committed plan to sell the gas trading and storage businesses.
(4) Represents the impact from measurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017.
(5) Represents the amount of accelerated depreciation derived from repowering wind farms in Renewables.
(6) Represents costs incurred in connection with the COVID-19 pandemic.
(7) Pre-merger costs incurred.
(8) Removal of the impact from Gas activity in the reconciliation to AVANGRID Net Income.

Note 25. Related Party Transactions

We engage in related party transactions that are generally billed at cost and in accordance with applicable state and federal commission regulations.

Related party transactions for the years ended December 31, 2020, 2019 and 2018, respectively, consisted of:

Years Ended December 31,	2020		2019		2018	
(Millions)	Sales To	Purchases From	Sales To	Purchases From	Sales To	Purchases From
Iberdrola, S.A.	$ 1	$ (43)	$ 1	$ (42)	$ 1	$ (38)
Iberdrola Renovables Energia, S.L.	$ —	$ (9)	$ —	$ (9)	$ —	$ (14)
Iberdrola Financiación, S.A.	$ —	$ (7)	$ —	$ (3)	$ —	$ (3)
Vineyard Wind	$ 9	$ —	$ 13	$ —	$ 3	$ —
Iberdrola Solutions	$ 2	$ —	$ 1	$ —	$ —	$ —
Iberdrola Energia Monterrey, S.A. de C.V.	$ —	$ —	$ —	$ —	$ 3	$ —
Iberdrola Canada Energy Services, Ltd	$ —	$ —	$ —	$ —	$ —	$ (5)
Other	$ —	$ —	$ 1	$ (3)	$ 2	$ (5)

In addition to the statements of income items above, we made purchases of turbines for wind farms from Siemens-Gamesa, in which Iberdrola had an 8.1% ownership interest until Iberdrola sold its interest in February 2020. After the sale, the turbine purchases are no longer considered related party transactions. The amounts capitalized for transactions while Siemens-Gamesa was considered a related party were $11 million and $18 million for the years ended December 31, 2020 and 2019, respectively.

Related party balances as of December 31, 2020 and 2019, respectively, consisted of:

As of December 31,	2020		2019	
(Millions)	Owed By	Owed To	Owed By	Owed To
Iberdrola, S.A.	$ 2	$ (43)	$ 1	$ (42)
Iberdrola Financiacion	$ —	$ (6)	$ —	$ (3)
Siemens-Gamesa (a)	$ —	$ —	$ —	$ (18)
Vineyard Wind	$ 4	$ —	$ 5	$ —
Iberdrola Solutions	$ 5	$ —	$ —	$ —
Other	$ 1	$ (1)	$ 4	$ (1)

(a) After Iberdrola's sale of its interest of Siemens-Gamesa in February 2020, transactions with Siemens-Gamesa are no longer considered related party.

Transactions with Iberdrola, our majority shareholder, relate predominantly to the provision and allocation of corporate services and management fees. All costs that can be specifically allocated, to the extent possible, are charged directly to the company receiving such services. In situations when Iberdrola corporate services are provided to two or more companies of AVANGRID, any costs remaining after direct charges are allocated using agreed upon cost allocation methods designed to allocate such costs. We believe that the allocation method used is reasonable. See Note 10 for a discussion of the Iberdrola Loan.

AVANGRID manages its overall liquidity position as part of the Iberdrola Group and is a party to a liquidity agreement with a financial institution, along with certain members of the Iberdrola Group. Cash surpluses remaining after meeting the liquidity requirements of AVANGRID and its subsidiaries may be deposited at the financial institution. Deposits, or credit balances, serve as collateral against the debit balances of other parties to the liquidity agreement. The balance at December 31, 2020 and 2019 was $0 and $150 million, respectively.

AVANGRID has a credit facility with Iberdrola Financiacion, S.A.U., a company of the Iberdrola Group. The facility has a limit of $500 million and matures on June 18, 2023. AVANGRID pays a facility fee of 10.5 basis points annually on the facility. As of both December 31, 2020 and 2019, there were no amounts outstanding under this credit facility.

We have a bi-lateral demand note agreement with Iberdrola Solutions, LLC, which had a notes receivable balance of $5 million and $0 for the years ended December 31, 2020 and 2019, respectively. Renewables has financial forward power contracts with Iberdrola Solutions to hedge Renewables merchant wind exposure in Texas.

See Note 22 - Equity Method Investments for information on transactions with our equity method investees.

There have been no guarantees provided or received for any related party receivables or payables. These balances are unsecured and are typically settled in cash. Interest is not charged on regular business transactions but is charged on outstanding loan balances. There have been no impairments or provisions made against any affiliated balances.

Note 26. Stock-Based Compensation

The Avangrid, Inc. Amended and Restated Omnibus Incentive Plan (the Plan) provides for, among other things, the issuance of performance stock units (PSUs), restricted stock units (RSUs) and phantom share units (Phantom Shares). As of December 31, 2020, the total number of shares authorized for stock-based compensation plans was 2,500,000.

Performance Stock Units

During 2016, 1,298,683 performance stock units (PSUs) were granted to certain officers and employees of AVANGRID. In 2017, 2018 and 2019, an additional 85,759, 75,350 and 3,881 PSUs, respectively, were granted to officers and employees of AVANGRID under the Plan with achievement measured based on certain performance and market-based metrics for the 2016 to 2019 time period.

The fair value of the PSUs on the grant date was $31.80 per share, which is expensed on a straight-line basis over the requisite service period of approximately seven years based on expected achievement. The fair value of the PSUs was determined using valuation techniques to forecast possible future stock prices, applying a weighted average historical stock price volatility of AVANGRID and industry companies, a risk-free rate of interest that is equal, as of the grant date, to the yield of the zero-coupon U.S. Treasury bill and a reduction for the respective dividend yield calculated based on the most recent quarterly dividend payment and the stock price as of the grant date.

In February 2020, a total number of 208,268 PSUs, before applicable taxes, were approved as earned by participants based on achievement of certain performance metrics related to the 2016 through 2019 plan and are payable in three equal installments, net of applicable taxes, in 2020, 2021 and 2022. The remaining unvested PSUs were forfeited. In May 2020, 42,777 shares of common stock were issued to settle the first installment payment and 2,605 PSUs were forfeited from the originally approved total number of PSUs.

Restricted Stock Units

In June and October 2018, pursuant to the Avangrid, Inc. Omnibus Incentive Plan two restricted stock units (RSUs) awards of 60,000 and 8,000 RSUs, respectively, were granted to certain officers of AVANGRID. The RSUs vest in full in one installment in June and December 2020, respectively for each award, provided that the grantee remains continuously employed with AVANGRID through the applicable date. The fair value on the grant date was determined based on a price of $50.40 per share for the June 2018 awards and $47.59 per share for the October 2018 awards. In June 2020, 60,000 RSU's, plus dividend equivalents accrued through the vesting period, were settled for $3 million in cash.

In August 2020, 5,000 RSUs were granted to an officer of AVANGRID. The RSUs vest in three equal installments in 2021, 2022 and 2023, provided that the grantee remains continuously employed with AVANGRID through the applicable vesting dates. The fair value on the grant date was determined based on a price of $48.99 per share.

Phantom Share Units

On March 18, 2020, 167,060 Phantom Shares were granted to certain AVANGRID executives and employees. These awards will vest in three equal installments in 2020, 2021 and 2022 and will be settled in a cash amount equal to the number of Phantom Shares multiplied by the closing share price of AVANGRID’s common stock on the respective vesting dates, subject to continued employment. The liability of these awards is measured based on the closing share price of AVANGRID’s common stock at each reporting date until the date of settlement. In June 2020, $2 million was paid to settle the first installment under this plan. As of December 31, 2020, the total liability is $2 million, which is included in other current and non-current liabilities.

The total stock-based compensation expense, which is included in "Operations and maintenance" of our consolidated statements of income for the years ended December 31, 2020, 2019 and 2018 was $14 million, $3 million and $2 million, respectively. The total income tax benefits recognized for stock-based compensation arrangements for each of the years ended December 31, 2020, 2019 and 2018, were $4 million, $1 million and $1 million, respectively.

A summary of the status of the AVANGRID's nonvested PSUs and RSUs as of December 31, 2020, and changes during the fiscal year ended December 31, 2020, is presented below:

	Number of PSUs and RSUs	Weighted Average Grant Date Fair Value
Nonvested Balance – December 31, 2019	1,274,280	$ 32.83
Granted	6,691	$ 49.20
Forfeited	(997,088)	$ 31.80
Vested	(141,716)	$ 41.44
Nonvested Balance – December 31, 2020	142,167	$ 32.42

As of December 31, 2020, total unrecognized costs for non-vested PSUs, RSUs and Phantom Shares was $3 million. The weighted-average period over which the PSU, RSU and Phantom Shares costs will be recognized is approximately 2 years.

The weighted-average grant date fair value of RSUs granted during the year was $49.20 per share for the year ended December 31, 2020.

Note 27. Restructuring and Severance Related Expenses

In 2017, we announced initial targeted voluntary workforce reductions predominantly within the Networks segment. Those actions primarily included: reducing our workforce through voluntary programs in various areas to better align our people resources with business demands and priorities; reorganizing our human resources function to substantially consolidate in Connecticut, as well as related costs to vacate a lease and relocate employees; and reducing our information technology workforce to make increasing use of external services for operations, support and development of systems. In 2019, we announced changes across the Company aimed to mitigate costs and deliver sustainable growth, including outsourcing and insourcing of certain areas of the Company and technology initiatives that help improve efficiency and reduce costs. For the years ended December 31, 2020, 2019 and 2018, those decisions and transactions resulted in restructuring charges of $2 million, $4 million and $3 million, respectively, for severance expenses, which are included in “Operations and maintenance” in the consolidated statements of income. "Depreciation and amortization" in our consolidated statements of income includes $4 million and $2 million, respectively, for the years ended December 31, 2020 and 2019 for restructuring activities. For the year ended December 31, 2020, the severance and lease restructuring charges reserves, which are recorded in “Other current liabilities” and “Other liabilities”, consisted of:

For the Year Ended December 31,	2020
	(Millions)
Beginning Balance	$ 5
Restructuring and severance related expenses	2
Payments	(4)
Ending Balance	$ 3

Note 28. Subsequent events

<u>Beatrice Corwin Living Irrevocable Trust, by and through Its Authorized Trustee, Robert Corwin v. Iberdrola, S.A., et. al.</u>

On January 8, 2021, the Beatrice Corwin Living Irrevocable Trust, by and through its Authorized Trustee, Robert Corwin filed a complaint in the Supreme Court of the State of New York Westchester County against Iberdrola and the members of the Company’s Board of Directors, as defendants, and the Company, as a nominal defendant with respect to certain counts contained in the complaint. The complaint alleges certain violations of fiduciary duties by Iberdrola and the members of the Company’s Board of Directors related to the existence of certain pre-emptive rights provided to Iberdrola in the Shareholder Agreement between the Company and Iberdrola, dated December 16, 2015, and the binding nature of such rights. We cannot predict the outcome of this matter.

On February 15, 2021, 1,181,031 PSUs were granted to certain officers and employees of AVANGRID pursuant to the Plan with achievement measured based on certain performance and market-based metrics for the 2021 to 2022 performance period. The PSUs will payable in three equal installments, net of applicable taxes, in 2023, 2024 and 2025.

On February 16, 2021, the board of directors of AVANGRID declared a quarterly dividend of $0.44 per share on its common stock. This dividend is payable on April 1, 2021 to shareholders of record at the close of business on March 5, 2021.

Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF INCOME
FOR THE YEARS ENDED December 31, 2020, 2019 AND 2018

Years Ended December 31,	**2020**	**2019**	**2018**
(Millions)			
Operating Revenues	$ —	$ —	$ —
Operating Expenses			
Operating expense	10	3	3
Taxes other than income taxes	(11)	(12)	(11)
Total Operating Expenses	(1)	(9)	(8)
Operating Income	1	9	8
Other Income			
Other income	35	59	48
Equity earnings of subsidiaries	641	678	596
Interest expense	(109)	(93)	(56)
Income Before Income Tax	568	653	596
Income tax (benefit) expense	(13)	(14)	9
Net Income	**$ 581**	**$ 667**	**$ 587**

See accompanying notes to Schedule I.

Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED December 31, 2020, 2019, AND 2018

Years Ended December 31,	**2020**	**2019**	**2018**
(Millions)			
Net Income	$ 581	$ 667	$ 587
Other comprehensive loss of subsidiaries	(16)	(11)	(25)
Comprehensive Income	**$ 565**	**$ 656**	**$ 562**

See accompanying notes to Schedule I.

Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
BALANCE SHEETS
AS OF December 31, 2020 AND 2019

As of December 31,	2020	2019
(Millions)		
Assets		
Current Assets		
Cash and cash equivalents	$ 1,438	$ 146
Accounts receivable from subsidiaries	124	22
Notes receivable from subsidiaries	1,489	2,529
Prepayments and other current assets	357	—
Total current assets	3,408	2,697
Investments in subsidiaries	18,356	16,812
Other assets		
Deferred income taxes	388	374
Other	3	3
Total other assets	391	377
Total Assets	**$ 22,155**	**$ 19,886**
Liabilities		
Current Liabilities		
Current portion of debt	$ —	$ 456
Notes payable	308	561
Notes payable to subsidiaries	1,375	1,674
Accounts payable and accrued liabilities	12	2
Accounts payable to subsidiaries	9	7
Interest accrued	9	10
Interest accrued subsidiaries	10	18
Dividends payable	136	136
Taxes accrued	—	24
Total current liabilities	1,859	2,888
Non-current debt	2,087	1,808
Non-current debt with affiliate	3,000	—
Total Liabilities	6,946	4,696
Equity		
Stockholders' Equity:		
Common stock	3	3
Additional paid-in capital	13,665	13,660
Treasury stock	(14)	(12)
Retained earnings	1,666	1,634
Accumulated other comprehensive loss	(111)	(95)
Total Equity	15,209	15,190
Total Liabilities and Equity	**$ 22,155**	**$ 19,886**

See accompanying notes to Schedule I.

Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED December 31, 2020, 2019, AND 2018

Years Ended December 31,	2020	2019	2018
(Millions)			
Net Cash used in Operating Activities	**$ (142)**	**$ (1,299)**	**$ (323)**
Cash Flow from Investing Activities			
Notes receivable from subsidiaries	(73)	633	462
Investments in subsidiaries	(591)	(399)	(48)
Return of capital from investments in subsidiaries	419	433	116
Other investments	(300)	—	—
Net Cash (used in) provided by Investing Activities	**(545)**	**667**	**530**
Cash Flow from Financing Activities			
(Repayments) receipts of short-term notes payable from subsidiaries, net	(14)	107	246
(Repayments) receipts of short-term notes payable	(253)	(27)	82
Proceeds from non-current debt	744	1,243	—
Proceeds from non-current debt with affiliate	3,000	—	—
Repayments of non-current debt	(950)	—	—
Repurchase of common stock	(2)	—	(4)
Issuance of common stock	(1)	—	(2)
Dividends paid	(545)	(545)	(537)
Net Cash provided by (used in) Financing Activities	**1,979**	**778**	**(215)**
Net Increase (Decrease) in Cash and Cash Equivalents	1,292	146	(8)
Cash and Cash Equivalents, Beginning of Year	146	—	8
Cash and Cash Equivalents, End of Year	**$ 1,438**	**$ 146**	**$ —**
Supplemental Cash Flow Information			
Cash paid for interest	$ 111	$ 85	$ 55
Cash paid (refunded) payment for income taxes	$ 65	$ 43	$ 55

See accompanying notes to Schedule I.

Note 1. Basis of Presentation

Avangrid, Inc. (AVANGRID) is a holding company and we conduct substantially all of our business through our subsidiaries. Substantially all of our consolidated assets are held by our subsidiaries. Accordingly, our cash flow and ability to meet our obligations are largely dependent upon the earnings of our subsidiaries and the distribution or other payment of their earnings to us in the form of dividends, loans or advances or repayment of loans and advances from us. Our condensed financial statements and related footnotes have been prepared in accordance with regulatory statute 210.12-04 of Regulation S-X. Our condensed financial statements should be read in conjunction with the consolidated financial statements and notes thereto of AVANGRID and subsidiaries (AVANGRID Group).

AVANGRID indirectly or directly owns all of the ownership interests of our significant subsidiaries. AVANGRID relies on dividends or loans from our subsidiaries to fund dividends to our primary shareholder.

AVANGRID's significant accounting policies are consistent with those of the AVANGRID Group. For the purposes of these condensed financial statements, AVANGRID's wholly owned and majority owned subsidiaries are recorded based upon our proportionate share of the subsidiaries net assets.

AVANGRID will file a consolidated federal income tax return that includes the taxable income or loss of all our subsidiaries for the 2020 tax period. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes separately and settles its current tax liability or benefit each year directly with AVANGRID pursuant to a tax sharing agreement between AVANGRID and our members.

Immaterial Corrections to Prior Periods

Our subsidiaries have identified various immaterial corrections primarily related to property, plant and equipment and deferred tax liabilities that originated in prior periods. AVANGRID determined that the cumulative impact of the corrections was not material to the results of operations, financial position or cash flows in previously issued financial statements and therefore, amendments of previously filed condensed financial information of AVANGRID are not required. However, we have revised the prior periods included within these financial statements to reflect these immaterial corrections. The corrections resulted in decreases of $33 million and $8 million in equity earnings and net income in the statements of income for the years ended December 31, 2019 and 2018, respectively, and a $47 million decrease in retained earnings and investments in subsidiaries in the balance sheet as of December 31, 2019. The revision decreased retained earnings by $6 million as of December 31, 2018. The revision had no net impact on the net cash provided by operating activities for the years ended December 31, 2019 and 2018.

Proposed Merger with PNMR

On October 20, 2020, AVANGRID, PNM Resources, Inc., a New Mexico corporation (PNMR) and NM Green Holdings, Inc., a New Mexico corporation and wholly-owned subsidiary of AVANGRID (Merger Sub), entered into an Agreement and Plan of Merger (Merger Agreement), pursuant to which Merger Sub is expected to merge with and into PNMR, with PNMR surviving the Merger as a direct wholly-owned subsidiary of AVANGRID (Merger). Pursuant to the Merger Agreement, each issued and outstanding share of the common stock of PNMR (PNMR common stock) (other than (i) the issued shares of PNMR common stock that are owned by AVANGRID, Merger Sub, PNMR or any wholly-owned subsidiary of AVANGRID or PNMR, which will be automatically cancelled at the time the Merger is consummated and (ii) shares of PNMR common stock held by a holder who has not voted in favor of, or consented in writing to, the Merger who is entitled to, and who has demanded, payment for fair value of such shares) will be converted, at the time the Merger is consummated, into the right to receive $50.30 in cash (Merger Consideration).

Consummation of the Merger (Closing) is subject to the satisfaction or waiver of certain customary closing conditions, including, without limitation, the approval of the Merger Agreement by the holders of at least a majority of the outstanding shares of PNMR common stock entitled to vote thereon, the absence of any material adverse effect on PNMR, the receipt of certain required regulatory approvals (including approvals from the Public Utility Commission of Texas (PUCT), the New Mexico Public Regulation Commission (NMPRC), the FERC, the Federal Communications Commission (FCC), the Committee on Foreign Investment in the United States (CFIUS), the Nuclear Regulatory Commission (NRC) and approval under the Hart-Scott-Rodino Antitrust Improvements Act of 1976), the Four Corners Divestiture Agreements (as defined below) being in full force and effect and all applicable regulatory filings associated therewith being made, as well as holders of no more than 15% of the outstanding shares of PNMR common stock validly exercising their dissenters' rights. On February 12, 2021, the shareholders of PNMR approved the proposed Merger. The Merger is currently expected to close in the second half of 2021.

The Merger Agreement also contains representations, warranties and covenants of PNMR, AVANGRID and Merger Sub, which are customary for transactions of this type. In addition, among other things, the Merger Agreement contains a covenant requiring PNMR to, prior to the Closing, enter into agreements (Four Corners Divestiture Agreements) providing for, and to make filings required to, exit from all ownership interests in the Four Corners Power Plant, all with the objective of having the closing date for such exit be no later than December 31, 2024.

In connection with the Merger, Iberdrola, S.A. has provided AVANGRID a commitment letter (Iberdrola Funding Commitment Letter), pursuant to which Iberdrola has unilaterally agreed to provide to AVANGRID, or arrange the provision to AVANGRID of, funds to the extent necessary for AVANGRID to consummate the Merger, including the payment of the aggregate Merger Consideration. To the extent AVANGRID wishes to effect a funding transaction under the Iberdrola Funding Commitment Letter in order to pay the Merger Consideration, the specific terms of any such transaction will be negotiated between Iberdrola and AVANGRID on an arm's length basis and must be approved by both (i) a majority of the members of the unaffiliated committee of the board of directors of AVANGRID, and (ii) a majority of the board of directors of AVANGRID. Under the terms of such commitment letter, Iberdrola S.A. has agreed to negotiate with AVANGRID the specific terms of any transaction effecting such funding commitment promptly and in good faith, with the objective that such terms shall be commercially reasonable and approved by AVANGRID. AVANGRID's and Merger Sub's obligations under the Merger Agreement are not conditioned upon AVANGRID obtaining financing.

The Merger Agreement provides for certain customary termination rights including the right of either party to terminate the Merger Agreement if the Merger is not completed on or before January 20, 2022 (subject to a three-month extension by either party if all of the conditions to the closing, other than the conditions related to obtaining regulatory approvals, have been satisfied or waived). The Merger Agreement further provides that, upon termination of the Merger Agreement under certain specified circumstances (including if AVANGRID terminates the Merger Agreement due to a change in recommendation of the board of directors of PNMR or if PNMR terminates the Merger Agreement to accept a superior proposal (as defined in the Merger Agreement)), PNMR will be required to pay AVANGRID a termination fee of $130 million. In addition, the Merger Agreement provides that (i) if the Merger Agreement is terminated by either party due to a failure of a regulatory closing condition and such failure is the result of AVANGRID's breach of its regulatory covenants, or (ii) AVANGRID fails to effect the Closing when all closing conditions have been satisfied and it is otherwise obligated to do so under the Merger Agreement, then, in either such case, upon termination of the Merger Agreement, AVANGRID will be required to pay PNMR a termination fee of $184 million as the sole and exclusive remedy. Upon the termination of the Merger Agreement under certain specified circumstances involving a breach of the Merger Agreement, either PNMR or AVANGRID will be required to reimburse the other party's reasonable and documented out-of-pocket fees and expenses up to $10 million (which amount will be credited toward, and offset against, the payment of any applicable termination fee).

Note 2. Common Stock

As of December 31, 2020, AVANGRID share capital consisted of 500,000,000 shares of common stock authorized, 309,794,917 shares issued and 309,077,300 shares outstanding, 81.5% of which are owned by Iberdrola, each having a par value of $0.01, for a total value of common stock of $3 million and additional paid in capital of $13,665 million. As of December 31, 2019, AVANGRID share capital consisted of 500,000,000 shares of common stock authorized, 309,752,140 shares issued and 309,005,272 shares outstanding, 81.5% of which were owned by Iberdrola, each having a par value of $ $0.01, for a total value of common stock capital of $3 million and additional paid in of $13,660 million. As of December 31, 2020 and 2019, we had 413,782 and 485,810 shares of common stock held in trust, respectively, and no convertible preferred shares outstanding. During the years ended December 31, 2020 and 2019, we issued 42,777 and 0 shares of common stock, respectively, and released 72,028 and 0 shares of common stock held in trust, respectively, each having a par value of $0.01. During January 2021, we released 292,594 shares of common stock held in trust.

We maintain a repurchase agreement with J.P. Morgan Securities, LLC. (JPM), pursuant to which JPM will, from time to time, acquire, on behalf of AVANGRID, shares of common stock of AVANGRID. The purpose of the stock repurchase program is to allow AVANGRID to maintain Iberdrola's relative ownership percentage at 81.5%. The stock repurchase program may be suspended or discontinued at any time upon notice. In May 2020, 42,777 shares were repurchased pursuant to the stock repurchase program. As of December 31, 2020, a total of 303,835 shares have been repurchased in the open market, all of which are included as AVANGRID treasury shares. As of December 31, 2020, the total cost of all repurchases, including commissions, was $14 million.

On February 16, 2021, the board of directors of AVANGRID declared a quarterly dividend of $0.44 per share on its common stock. This dividend is payable on April 1, 2021 to shareholders of record at the close of business on March 5, 2021.

Note 3. Long-Term Debt

In 2017, AVANGRID issued $600 million aggregate principal amount of its 3.15% notes maturing in 2024.

On May 16, 2019, AVANGRID issued $750 million aggregate principal amount of its 3.80% notes maturing in 2029. Proceeds of the offering were used to finance and/or refinance, in whole or in part, one or more eligible renewable energy generation facilities. Net proceeds of the offering after the price discount and issuance-related expenses were $743 million.

On April 9, 2020, AGR issued $750 million aggregate principal amount of unsecured notes maturing in 2025 at a fixed interest rate of 3.20%. Net proceeds of the offering after the price discount and issuance-related expenses were $744 million.

Iberdrola Loan

On December 14, 2020, AVANGRID entered into an intra-group loan agreement with Iberdrola which provided AVANGRID with an unsecured subordinated loan in an aggregate principal amount of $3,000 million (the Iberdrola Loan).

The Iberdrola Loan bears interest (i) from December 16, 2020 until June 15, 2021, at an interest rate of 0.20%, which increases one basis point each month following the first month of the term of the Iberdrola Loan up to a maximum interest rate of 0.25%, and (ii) from June 16, 2021 until the Iberdrola Loan and any accrued and unpaid interest is repaid in its entirety, at AVANGRID's equity cost of capital as published by Bloomberg. Interest is payable on a monthly basis in arrears.

AVANGRID is required to repay the Iberdrola Loan in full upon certain equity issuances by AVANGRID in which Iberdrola participates or a change of control of AVANGRID. In addition, on or after June 15, 2021, upon five business days' notice to Iberdrola, AVANGRID may voluntarily repay the Iberdrola Loan and any accrued and unpaid interest, in whole or in part, without prepayment premium or penalty if there is a change in AVANGRID's business plan and AVANGRID determines that the Iberdrola Loan is no longer required. The intra-group loan agreement contains certain customary affirmative and negative covenants and events of default.

As of December 31, 2020, the Iberdrola Loan had no current maturities and is included in "Non-current debt with affiliate" on our condensed balance sheet as we do not intend on repaying the Iberdrola Loan with current assets. Proceeds from the Iberdrola Loan of $1,438 million and $300 million, respectively, are included in "cash and cash equivalents" and "prepayments and other current assets" on our condensed balance sheet as of December 31, 2020. The remainder of the proceeds reduced our commercial paper balance.

Note 4. Cash Dividends Paid by Subsidiaries

Cash dividends paid by subsidiary are as follows:

Years ended December 31,	2020	2019	2018
(millions)			
AVANGRID Networks	$ 419	$ 433	$ 116

For the years ended December 31, 2020, 2019 and 2018, AVANGRID made capital contributions to Networks of $590 million, $158 million and $50 million, respectively.

During 2020 and 2019, AVANGRID recorded a net non-cash contribution and dividend of $423 million and $219 million, respectively, to and from its subsidiaries to zero out their account balances of notes receivable and payable.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer, or CEO, and our Chief Financial Officer, or CFO, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act), as of the end of the period covered by this Annual Report on Form 10-K. Based on such evaluation, our CEO and CFO have concluded that as of such date, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and (ii) accumulated and communicated to the Company's management, including its CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Report of Management on Internal Control Over Financial Reporting

The management of AVANGRID is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. AVANGRID's internal control system over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. AVANGRID's internal control over financial reporting includes those policies and procedures that:

1. pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company;

2. provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and

3. provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in condition, or that the degree of compliance with the policies or procedures may deteriorate.

AVANGRID's management assessed the effectiveness of AVANGRID's internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) ("COSO") in Internal Control-Integrated Framework. Based on this assessment, management determined that our internal control over financial reporting was effective as of December 31, 2020.

Our independent registered public accounting firm, KPMG LLP, has issued an audit report on the Company's internal control over financial reporting, which appears in Part II, Item 8 of this Form 10-K.

Changes in Internal Control

There were no changes in our internal control over financial reporting identified in connection with the evaluation required by Rules 13a-15(d) and 15d-15(d) of the Exchange Act during the quarter ended December 31, 2020 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

For information regarding our executive officers, see Part I of this Annual Report on Form 10-K. Additional information required by this item is incorporated by reference to our Proxy Statement for the 2021 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2020.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2021 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2020.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2021 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2020.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2021 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2020.

Item 14. ***Principal Accountant Fees and Services.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2021 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2020.

Part IV

Item 15. ***Exhibits and Financial Statement Schedules.***

a) The following documents are made a part of this Annual Report on Form 10-K:

1. Financial Statements—Our consolidated financial statements are set forth under Part II, Item 8 “Financial Statements and Supplementary Data.”
2. Financial Statement Schedules— Our financial statement schedules are set forth under Part II, Item 8 “Financial Statements and Supplementary Data.”
3. Exhibits—The following instruments and documents are included as exhibits to this report.

Exhibit Number	Exhibit Description
2.1	Agreement and Plan of Merger, dated as of February 25, 2015, by and among Avangrid, Inc. (formerly Iberdrola USA, Inc.), Green Merger Sub, Inc. and UIL Holdings Corporation (incorporated herein by reference to Annex A to the proxy statement/prospectus included as Exhibit 2.1 in our Registration Statement on Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
2.2	Agreement and Plan of Merger, dated as of October 20, 2020, by and among PNM Resources, I Inc., Avangrid, Inc. and NM Green Holdings, Inc. (incorporated herein by reference to Exhibit 2.1 to Form 8-K file with the Securities and Exchange Commission on October 21, 2020).
3.1	Certificate of Incorporation of Avangrid, Inc. (incorporated herein by reference to Exhibit 3.2 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2015).
3.2	Amended and Restated Bylaws of Avangrid, Inc. (incorporated herein by reference to Exhibit 3.1 of AVANGRID’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2017 filed with the Securities and Exchange Commission on August 1, 2017).
4.1	Specimen Common Stock Certificate (incorporated herein by reference to Exhibit 4.1 to Form S-4/A filed with the Securities and Exchange Commission on October 21, 2015).
4.2	Senior Indenture, dated as of October 7, 2010, between UIL Holdings Corporation and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.1 of UIL Holdings Corporation’s Current Report on Form 8-K filed with the Securities and Exchange Commission on October 7, 2010).
4.3	First Supplemental Indenture, dated as of October 7, 2010, between UIL Holdings Corporation and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.2 of UIL Holdings Corporation’s Current Report on Form 8-K filed with the Securities and Exchange Commission on October 7, 2010).
4.4	Second Supplemental Indenture, dated as of December 16, 2015, among UIL Holdings Corporation, Green Merger Sub, Inc. and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2015).
4.5	Third Supplemental Indenture, dated as of December 19, 2016, among Avangrid, Inc., UIL Holdings Corporation and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.5 of AVANGRID’s Annual Report on Form 10-K for the fiscal year ended December 31, 2016 filed with the Securities and Exchange Commission on March 10, 2017).
4.6	Indenture, dated as of November 21, 2017, between the Company and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed with the Securities and Exchange Commission on November 21, 2017).
4.7	First Supplemental Indenture, dated November 21, 2017, between the Company and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed with the Securities and Exchange Commission on November 21, 2017).

Exhibit Number	Exhibit Description
4.8	Form of Global Note Representing the Notes (incorporated herein by reference to Exhibit 4.3 to Form 8-K filed with the Securities and Exchange Commission on November 21, 2017).
4.9	Second Supplemental Indenture, dated as of May 16, 2019, among Avangrid, Inc. and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed with the Securities and Exchange Commission on May 16, 2019).
4.10	Third Supplemental Indenture, dated April 9, 2020, between the Company and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed with the Securities and Exchange Commission on April 9, 2020).
4.11	Form of Global Note Representing the Notes (included in Third Supplemental Indenture, dated April 9, 2020, between the Company and The Bank of New York Mellon, as trustee and incorporated herein by reference to Exhibit 4.2 of AVANGRID's Current Report on Form 8-K filed with the SEC on April 9, 2020).
4.12	Description of Avangrid, Inc.'s Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (incorporated herein by reference to Exhibit 4.9 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2019 filed with the Securities and Exchange Commission on March 2, 2020).
10.1	Shareholder Agreement, dated as of December 16, 2015, by and between Avangrid, Inc. and Iberdrola, S.A. (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2015).
10.2	Service Agreement, dated January 1, 2014, between Iberdrola USA, Inc. Management Corporation and Avangrid, Inc. (formerly Iberdrola USA, Inc.) (incorporated herein by reference to Exhibit 10.2 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.3	Accession Agreement, dated September 16, 2011, between Iberdrola Renewables Holdings, Inc. and Bank Mendes Gans N.V. (incorporated herein by reference to Exhibit 10.14 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.4	Provisions to be Applied to U.S. Participants in Relation to the Regulations for the "2014-2016 Strategic Bonus" for Senior Officers and Officers of Iberdrola, S.A. and Its Group of Companies (incorporated herein by reference to Exhibit 10.20 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.5	Employment Agreement dated October 1, 2010 among Robert Daniel Kump, Iberdrola USA Networks, Inc. (formerly Iberdrola USA, Inc.) and Iberdrola USA Management Corporation (incorporated herein by reference to Exhibit 10.23 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.6	Service Contract dated January 16, 2014 between Robert Daniel Kump and Avangrid, Inc. (incorporated herein by reference to Exhibit 10.24 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.7	Employment Agreement dated March 1, 2008 between R. Scott Mahoney and Iberdrola USA Management Corporation (formerly Energy East Management Corporation) (incorporated herein by reference to Exhibit 10.27 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015).†
10.8	Framework Agreement for the Provision of Corporate Services for Iberdrola and the Companies of its Group, and the Declaration of Acceptance, dated July 16, 2015 (incorporated herein by reference to Exhibit 10.28 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.9	Equipment Supply Agreement dated December 28, 2014 between Iberdrola Renewables, LLC and Gamesa Wind US, LLC (incorporated herein by reference to Exhibit 10.29 to Form S-4/A filed with the Securities and Exchange Commission on November 6, 2015).

Exhibit Number	Exhibit Description
10.10	Agreement and Release dated September 25, 2009 between Robert Daniel Kump and Iberdrola USA Management Corporation (formerly Energy East Management Corporation) (incorporated herein by reference to Exhibit 10.31 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.11	Form of Indemnification Agreement between Avangrid, Inc. (formerly Iberdrola USA, Inc.) and its directors and officers (incorporated herein by reference to Exhibit 10.32 to Form S-4/A filed with the Securities and Exchange Commission on October 21, 2015).†
10.12	UIL Holdings Corporation 2008 Stock and Incentive Compensation Plan as Amended and Restated May 14, 2013 (incorporated herein by reference to Exhibit 99.1 to Form S-8 filed with the Securities and Exchange Commission on December 16, 2015).†
10.13	UIL Holdings Corporation Deferred Compensation Plan Grandfathered Benefits Provisions, dated August 4, 2008 (incorporated herein by reference to Exhibit 99.2 to Form S-8 filed with the Securities and Exchange Commission on December 16, 2015).†
10.14	UIL Holdings Corporation Deferred Compensation Plan Non-Grandfathered Benefits Provisions, as amended and restated effective dated January 1, 2013 (incorporated herein by reference to Exhibit 99.3 to Form S-8 filed with the Securities and Exchange Commission on December 16, 2015).†
10.15	Amended and Restated UIL Holdings Corporation Change In Control Severance Plan II, dated August 4, 2008 (incorporated herein by reference to Exhibit 10.28a of UIL Holdings Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).†
10.16	Employment Agreement, dated as of January 1, 2016, among Avangrid, Inc., Avangrid Service Company and James P. Torgerson (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on April 22, 2016).†
10.17	Commercial Paper/Certificates of Deposit Issuing and Paying Agent Agreement dated May 13, 2016 among Avangrid, Inc., as Issuer, and Bank of America, National Association, as Issuing and paying Agent (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 filed with the Securities and Exchange Commission on August 4, 2016).
10.18	Form of Commercial Paper Dealer Agreement among Avangrid, Inc., as Issuer, and various Dealers (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 filed with the Securities and Exchange Commission on August 4, 2016).
10.19	Form of Performance Stock Unit Grant Agreement (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on July 19, 2016).†
10.20	Avangrid, Inc. Omnibus Incentive Plan (incorporated herein by reference to Form S-8 filed with the SEC on July 21, 2016).†
10.21	Uncommitted Line of Credit for Standby Letters of Credit Agreement, dated as of December 2, 2016, between Avangrid, Inc. and Crédit Agricole Corporate (incorporated herein by reference to Exhibit 10.44 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2016 filed with the Securities and Exchange Commission on March 10, 2017).
10.22	Substitution Agreement, dated as of December 19, 2016, between UIL Holdings Corporation and Avangrid, Inc. (incorporated herein by reference to Exhibit 10.45 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2016 filed with the Securities and Exchange Commission on March 10, 2017).
10.23	Amended and Restated Avangrid, Inc. Omnibus Incentive Plan (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 filed with the Securities and Exchange Commission on May 5, 2017).†

Exhibit Number	Exhibit Description
10.24	Customer Liquidity Agreement, dated December 1, 2017, between Avangrid, Inc., Bank of America, National Association, Iberdrola, S.A., Iberdrola Mexico, S.A. de C.V., and Scottish Power Ltd. (incorporated herein by reference to Exhibit 10.37 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2017 filed with the Securities and Exchange Commission on March 26, 2018).
10.25	Underwriting Agreement, dated November 16, 2017, by and among the Avangrid, Inc., BBVA Securities Inc., BNP Paribas Securities Corp., Citigroup Global Markets Inc., and Wells Fargo Securities, LLC (incorporated herein by reference to Exhibit 1.1 to Form 8-K filed with the Securities and Exchange Commission on November 21, 2017).
10.26	Purchase Agreement, dated January 31, 2018, between Avangrid Renewables Holdings, Inc. and CCI U.S. Asset Holdings LLC (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 filed with the Securities and Exchange Commission on May 3, 2018).
10.27	Purchase Agreement, dated February 16, 2018, between Avangrid Renewables Holdings, Inc. and Amphora Gas Storage USA, LLC (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 filed with the Securities and Exchange Commission on May 3, 2018).
10.28	Restricted Stock Unit Grant Notice and Agreement dated June 7, 2018, between Avangrid, Inc. and James P. Torgerson (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).†
10.29	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and NSTAR Electric Company (d/b/a Eversource) (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.30	Transmission Service Agreement, dated June 13, 2018, among Central Maine Power Company, Massachusetts Electric Company (d/b/a National Grid), and Nantucket Electric Company (d/b/a National Grid) (incorporated herein by reference to Exhibit 10.3 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.31	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and Fitchburg Gas & Electric Light Company (d/b/a Unitil) (incorporated herein by reference to Exhibit 10.4 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.32	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.5 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.33	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.6 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.34	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.7 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).

Exhibit Number	Exhibit Description
10.35	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.8 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.36	Revolving Credit Agreement, dated as of June 29, 2018, among Avangrid, Inc., New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, Central Maine Power Company, The United Illuminating Company, Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company, The Berkshire Gas Company, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, MUFG Bank, LTD. and Santander Bank, N.A., as Co-Documentation Agents, Bank of America, N.A., as Syndication Agent, Banco Bilbao Vizcaya Argentaria, S.A. New York Branch, as Sustainability Agent, and JPMorgan Chase Bank, N.A., Merrill Lynch, Pierce, Fenner & Smith Incorporated, , MUFG Bank, LTD., Santander Bank, N.A., and BBVA Securities, as Joint Lead Arrangers and Joint Bookrunners (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on June 29, 2018).
10.37	Employment Agreement, effective as of July 8, 2018, between Douglas K. Stuver and Avangrid Management Company, LLC (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on July 20, 2018).†
10.38	Executive Variable Pay Plan (incorporated by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on February 21, 2018).†
10.39	First Amendment to Transmission Service Agreement dated October 9, 2018 by and between Central Maine Power Company and NSTAR Electric Company (d/b/a Eversource) (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed with the SEC on October 15, 2018).
10.40	First Amendment to Transmission Service Agreement dated October 9, 2018 by and among Central Maine Power Company, Massachusetts Electric Company (d/b/a National Grid) and Nantucket Electric Company (d/b/a National Grid) (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed with the SEC on October 15, 2018).
10.41	First Amendment to Transmission Service Agreement dated October 9, 2018 by and between Central Maine Power Company and Fitchburg Gas and Electric Light Company (d/b/a Unitil) (incorporated herein by reference to Exhibit 10.3 to Form 8-K filed with the SEC on October 15, 2018).
10.42	Amended and Restated Executive Variable Pay Plan (incorporated by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on February 20, 2019).†
10.43	Underwriting Agreement, dated May 14, 2019, by and among the Avangrid, Inc., Credit Agricole Securities (USA) Inc, MUFG Securities Americas Inc., Citigroup Global Markets Inc., and Wells Fargo Securities, LLC (incorporated herein by reference to Exhibit 1.1 to Form 8-K filed with the Securities and Exchange Commission on May 16, 2019).
10.44	Term Loan Credit Agreement, dated December 31, 2019, among Avangrid, Inc., The Several Lenders, Mizuho Bank, LTD and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed with the Securities and Exchange Commission on January 7, 2020).
10.45	Employment Agreement, dated March 30, 2004 between Anthony Marone III and The United Illuminating Company (incorporated herein by reference to Exhibit 10.51 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2019 filed with the Securities and Exchange Commission on March 2, 2020).†
10.46	First Amendment to Employment Agreement, dated as of November 18, 2004, between Anthony Marone III and The United Illuminating Company (incorporated herein by reference to Exhibit 10.52 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2019 filed with the Securities and Exchange Commission on March 2, 2020).†

Exhibit Number	Exhibit Description
10.47	Second Amendment to Employment Agreement, dated as of August 4, 2008, between Anthony Marone III and The United Illuminating Company (incorporated herein by reference to Exhibit 10.53 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2019 filed with the Securities and Exchange Commission on March 2, 2020).†
10.48	Letter Agreement, dated September 20, 2016, between Anthony Marone III and Avangrid, Inc (incorporated herein by reference to Exhibit 10.54 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2019 filed with the Securities and Exchange Commission on March 2, 2020).†
10.49	Second Amended and Restated Employment Agreement, dated as of May 4, 2020, between Anthony Marone III and Avangrid, Inc.†*
10.50	Underwriting Agreement, dated April 7, 2020, by and among Avangrid, Inc. and BBVA Securities Inc., BNP Paribas Securities Corp., BofA Securities, Inc. and MUFG Securities Americas Inc., as representatives of the several Underwriters named therein (incorporated herein by reference to Exhibit 1.1 to Form 8-K filed with the Securities and Exchange Commission on April 9, 2020).
10.51	Employment Agreement, dated June 11, 2020, by and between Avangrid Management Company, LLC and Dennis V. Arriola (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).†
10.52	Revolving Credit Agreement, dated June 29, 2020, among Avangrid, Inc., the several lenders from time to time parties thereto, Mizuho Bank, Ltd., as administrative agent, and The Bank of Nova Scotia and Banco Bilbao Vizcaya Argentaria, S.A. New York Branch, as co-syndication agents (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.53	Amendment No. 2 to the Revolving Credit Agreement, dated June 29, 2020, among Avangrid, Inc., New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, Central Maine Power Company, The United Illuminating Company, Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company, The Berkshire Gas Company, the several banks and other financial institutions or entities from time to time parties thereto, JPMorgan Chase Bank, N.A., as administrative agent, and Bank of America, N.A., as syndication agent, MUFG Bank, Ltd. and Santander Bank, N.A., as co-documentation agents, and Banco Bilbao Vizcaya Argentaria, S.A. New York Branch, as sustainability agent (incorporated herein by reference to Exhibit 10.3 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.54	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and NSTAR Electric Company (d/b/a Eversource) (incorporated herein by reference to Exhibit 10.4 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.55	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and among Central Maine Power Company, Massachusetts Electric Company (d/b/a National Grid), and Nantucket Electric Company (d/b/a National Grid) incorporated herein by reference to Exhibit 10.5 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.56	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and Fitchburg Gas and Electric Light Company (d/b/a Unitil) (incorporated herein by reference to Exhibit 10.6 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.57	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.7 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).

Exhibit Number	Exhibit Description
10.58	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.8 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.59	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.9 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.60	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.10 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.61	Intra-Group Loan Agreement, dated December 14, 2020, between Avangrid, Inc. and Iberdrola, S.A. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2020).
21.1	Significant subsidiaries of the Registrant.*
23.1	Consent of KPMG LLP, independent registered public accounting firm of Avangrid, Inc.*
31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32	Chief Executive Officer and Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.*
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.*
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.*
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document.*
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.*
104	The cover page from the Company's Annual Report on Form 10-K for the year ended December 31, 2019, formatted as Inline XBRL and contained in Exhibit 101.

* Filed herewith.

† Compensatory plan or agreement.

— Confidential treatment has been requested for portions of this document. The omitted portions of this document have been submitted separately to the Securities and Exchange Commission.

The foregoing list of exhibits does not include instruments defining the rights of the holders of certain long-term debt of Avangrid, Inc. and its subsidiaries where the total amount of securities authorized to be issued under the instrument does not exceed ten percent (10%) of the total assets of Avangrid, Inc. and its subsidiaries on a consolidated basis; and Avangrid, Inc. hereby agrees to furnish a copy of each such instrument to the SEC on request.

Item 16. ***Form 10-K Summary.***

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Avangrid, Inc.

Date: March 1, 2021

By: /s/ Dennis V. Arriola
Dennis V. Arriola
Director and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Dennis V. Arriola Dennis V. Arriola	Director and Chief Executive Officer (Principal Executive Officer)	March 1, 2021
/s/ Douglas K. Stuver Douglas K. Stuver	Chief Financial Officer (Principal Financial Officer)	March 1, 2021
/s/ Scott M. Tremble Scott M. Tremble	Controller (Principal Accounting Officer)	March 1, 2021
/s/ Ignacio S. Galán Ignacio S. Galán	Chairman of the Board	February 26, 2021
/s/ John E. Baldacci John E. Baldacci	Director	February 26, 2021
/s/ Daniel Alcain López Daniel Alcain López	Director	February 26, 2021
/s/ Pedro Azagra Blázquez Pedro Azagra Blázquez	Director	February 26, 2021
/s/ Robert Duffy Robert Duffy	Director	February 26, 2021
/s/ Teresa Herbert Teresa Herbert	Director	February 26, 2021
/s/ Patricia Jacobs Patricia Jacobs	Director	February 26, 2021
/s/ John L. Lahey John L. Lahey	Director	February 26, 2021
/s/ José Ángel Marra Rodríquez José Ángel Marra Rodríquez	Director	February 26, 2021
/s/ Santiago Martinez Garrido Santiago Martinez Garrido	Director	February 26, 2021
/s/ José Sáinz Armada José Sáinz Armada	Director	February 26, 2021
/s/ Alan D. Solomont Alan D. Solomont	Director	February 26, 2021
/s/ Elizabeth Timm Elizabeth Timm	Director	February 26, 2021

SECOND AMENDED AND RESTATED EMPLOYMENT AGREEMENT

THIS SECOND AMENDED AND RESTATED EMPLOYMENT AGREEMENT (the "Agreement") is entered into by and among Avangrid Service Company, a Delaware corporation (the "Company"), a wholly-owned subsidiary of Avangrid, Inc., and Anthony Marone, III (the "Executive") on May 4, 2020, and effective as of June 15, 2019 (the "Effective Date").

WHEREAS, The United Illuminating Company, a Connecticut company ("UI"), a wholly-owned subsidiary of Avangrid, Inc., previously entered into an Employment Agreement with the Executive, dated and effective as of March 30, 2004 ("Employment Agreement"), a First Amendment to the Employment Agreement, dated and effective as of November 18, 2004 ("First Amendment"), and a Second Amendment to the Employment Agreement, dated and effective as of August 4, 2008 ("Second Amendment") (the Employment Agreement, First Amendment and Second Amendment are collectively referred to as the "UI Agreements");

WHEREAS, the Executive was appointed to CEO and President of UIL Holdings Corporation, a Connecticut corporation ("UIL"), a wholly-owned subsidiary of Avangrid, Inc., as of on or about September 12, 2016 and executed a letter on September 26, 2016 indicating his understanding and acceptance of the terms of his employment as the CEO and President of UIL ("Letter Agreement") (the UI Agreements and the Letter Agreement are collectively referred to as the "Previous Agreements");

WHEREAS, the Executive was appointed CEO and President of Avangrid Networks, Inc., a Maine corporation and wholly-owned subsidiary of Avangrid, Inc., as of on or about June 6, 2019;

WHEREAS, the Company desires to continue to employ the Executive as CEO and President of Avangrid Networks, Inc., and the Executive desires to be so employed by the Company, and the parties hereto wish to amend and restate the terms of the Previous Agreements and desire to be bound by the terms of this Agreement, which shall supersede and replace all prior oral or written employment agreements, including, but not limited to the Previous Agreements;

NOW THEREFORE, in consideration of the foregoing and the respective covenants and agreements of the parties contained herein, and the services to be rendered to the Company pursuant hereto, the parties hereby agree as follows:

(1) EMPLOYMENT; TERM

(a) The Company hereby agrees to employ the Executive, and the Executive hereby agrees to serve the Company, at the pleasure of the Board of Directors of Avangrid Networks, Inc. (the "Board") and the CEO and President of Avangrid, Inc., all upon the terms and conditions set forth herein, until Executive's employment is terminated in accordance with the terms of this Agreement (the "Term").

(b) The Term will commence on the Effective Date and continue until the Date of Termination (as defined in Section 5(e) of this Agreement).

(2) POSITION AND DUTIES

(a) The Executive shall be employed by the Company as the CEO and President of Avangrid Networks, Inc., or in such other equivalent or higher position as the Board may determine. The Executive shall:

(i) accept such employment and perform and discharge, faithfully, diligently and to the best of the Executive's abilities, the duties and obligations of the Executive's office and such other duties as may from time to time be assigned to the Executive by, or at the direction of, the Board or the CEO and President of Avangrid, Inc.; and

(ii) devote substantially all of the Executive's working time and efforts to the business and affairs of the Company, Avangrid Networks, Inc. and their respective subsidiaries and affiliates.

(b) Prior to a Change in Control (as defined in Section 4(c) of this Agreement), in the event that the Executive is named by the Board to a position higher in rank or compensation than that applicable at the commencement of the Term, nothing in this Agreement shall obligate the Company to continue such Executive in such higher position; and the Company shall not be deemed in "Breach" of the Agreement (as defined in Section 5(d) of this Agreement) for failure to continue the Executive in such higher position.

(c) As of a Change in Control as herein defined, for the twenty-four month period after such Change in Control, the Company's employment of the Executive shall be without diminishment in the Executive's management responsibilities, duties or powers. In the event that the Executive's employment is not so continued, the Executive may be eligible for benefits on account of a Constructive Termination in accordance with this Agreement.

(3) PLACE OF PERFORMANCE

In his employment by the Company, the Executive shall be based within a fifty (50)-mile radius of the current executive offices of Avangrid, Inc. in Orange, Connecticut.

(4) COMPENSATION

(a) **Base Salary**. Commencing on January 5, 2020, the Executive shall receive a base salary ("Base Salary") at an annual rate of Five Hundred Fifty Thousand Dollars ($550,000.00), payable in accordance with the then customary payroll practices of the Company. The Executive's performance and Base Salary shall be reviewed by the Board at least annually and may be revised upward as a result of any such review. The Executive's Base Salary may be revised downward by the Board contemporaneously with any general reduction of the salary rates of the Company's other executives.

(b) **Incentive Compensation**. During the Term of the Executive's employment hereunder, the Executive shall be eligible to participate in the Company's Executive Variable Pay Plan or any successor plan thereto (the "EVP"). Commencing with the fiscal year 2020 performance period under the EVP, the Executive's EVP opportunity at Target for each EVP performance period during the Term shall be equal to 65% of his Base Salary then in effect for such EVP performance period, and the maximum opportunity shall be equal to 130% of his Base Salary then in effect for such EVP performance period. Executive shall also be eligible to participate in the Avangrid Long-Term Incentive Plan and any successor plan thereto (the "LTIP"), in accordance with and subject to its terms. Entitlement to participation, and continued participation, in any LTIP shall be conditioned upon the Executive fully complying with any stock ownership and retention guidelines from time to time established and promulgated by the Board.

For purposes of this Agreement, the Executive's "Accrued Incentive Compensation" shall mean the amount of any annual short-term incentive compensation earned with respect to the calendar year ended prior to the Date of Termination (as defined in Section 5(e) of this Agreement) but not yet paid as of the Executive's Date of Termination.

The Executive's "Stub-Period Incentive Compensation" shall mean the annual short-term incentive compensation being earned in the year in which the Executive terminates employment, pro-rated for the year in which he terminates service, and shall be equal to that short-term annual incentive compensation payment to which the Executive would be entitled, if any, under the terms of the Company's executive incentive compensation plan, calculated as if he had been employed by the Company on the last day of the year including his Date of Termination, based on actual performance with respect to the achievement of Company goals multiplied by a fraction, the numerator of which is the number of days which have elapsed in such year through the Date of Termination and the denominator of which is 365. The Company shall determine in its discretion the composition of the Executive's scorecard. In the event that the 'gate', if any, is not achieved with respect to Company goals, then no Stub-Period

Incentive Compensation will be paid. Any Stub-Period Incentive Compensation payable upon termination of the Executive shall be paid in accordance with Section (6)(e) of this Agreement.

(c) **Change in Control Severance Plan**. A “Change in Control” occurs on the date on which any of the following events occur: a change in the ownership of the Company, Avangrid, Inc. or Iberdrola S.A. (collectively an “Employing Company”); a change in the effective control of the Employing Company; and a change in the ownership of a substantial portion of the assets of the Employing Company.

(i) A change in the ownership of the Employing Company occurs on the date on which any one person, or more than one person acting as a group, acquires ownership of stock of the Employing Company that, together with stock held by such person or group constitutes more than 50% of the total fair market value or total voting power of the stock of the Employing Company.

(ii) A change in the effective control of the Employing Company occurs on the date on which either (1) a person, or more than one person acting as a group, acquires ownership of stock of the Employing Company possessing 30% or more of the total voting power of the stock of the Employing Company, taking into account all such stock acquired during the 12-month period ending on the date of the most recent acquisition, or (2) a majority of the members of the Employing Company’s Board of Directors is replaced during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of such Board of Directors prior to the date of the appointment or election, but only if no other corporation is a majority shareholder of the Employing Company.

(iii) A change in the ownership of a substantial portion of assets occurs on the date on which any one person, or more than one person acting as a group, other than a person or group of persons that is related to the Employing Company, acquires assets from the Employing Company, that have a total gross fair market value equal to or more than 50% of the total gross fair market value of all of the assets of the Employing Company immediately prior to such acquisition or acquisitions, taking into account all such assets acquired during the 12-month period ending on the date of the most recent acquisition.

(iv) An event constitutes a Change in Control with respect to the Executive only if he performs services for the Employing Company that has experienced the Change in Control, or the Executive’s relationship to the affected Employing Company otherwise satisfies the requirements of Treasury Regulation § 1.409A-3(i)(5)(ii).

(v) In determining whether a person or group has acquired a percentage of stock, stock of the Employing Company held pursuant to the terms of an employee benefit plan of the Employing Company (or any subsidiary thereof) in a suspense account or otherwise unallocated to a participant's account shall be disregarded to the extent that expressing the applicable percentage as a fraction, such shares shall not be included in the numerator, but such shares will be included in the denominator.

(vi) the determination as to the occurrence of a Change in Control shall be based on objective facts and in accordance with the requirements of Internal Revenue Service Code ("Code") §409A.

(d) **Business Expenses**. During the Term, the Executive shall be entitled to receive prompt reimbursement for all reasonable employment-related business expenses incurred by the Executive, in accordance with the policies and procedures established by the Board from time to time for all of the Company’s executives, provided that the Executive properly accounts therefor.

(e) **Benefit Programs**. During the Term of the Executive’s employment hereunder and to the extent he meets the applicable eligibility requirements, the Executive shall be entitled to participate in and receive benefits under all of the Company’s employee benefit plans, programs and arrangements for its similarly situated executives on the same terms and conditions that apply to such executives, including, without limitation, any plan or program of an affiliated company in which the Company is a participating employer, but only for so long as the Company remains a participating employer, this includes, but is not limited to, The United Illuminating Company Pension Plan, as amended, and according to its terms, and the Supplemental Executive Retirement Plan of The United Illuminating Company ("UI SERP"), according to its terms. Except as otherwise expressly provided, nothing paid to the Executive under any such plan, program or arrangement presently in effect or made available by the Company in the future shall be deemed to be in lieu of compensation to the Executive under any other Section of this Agreement. Nothing in this Agreement shall require the Company to maintain a particular, benefit, benefit plan or program, or preclude the Company from modifying, amending or terminating any such benefit, plans, programs, Company policy or arrangements, including its participation therein, or eliminating, reducing or otherwise changing any benefit provided thereunder, so long as such change similarly affects all similarly situated employees of the Company and is in compliance with applicable law.

(f) **Vacations and Holidays**. The Executive shall be entitled to that number of weeks of paid vacation in each calendar year determined by the Board from time to time to be available to similarly situated Company executives, and shall also be entitled to all paid holidays afforded by the Company to its management employees.

(5) TERMINATION

(a) **Death or Disability**. The Executive's employment hereunder shall terminate upon the Executive's death or termination due to disability (as described in Section 6(a) of this Agreement).

(b) **Termination by Company for Cause**. The Company may at any time by written notice to the Executive terminate the Executive's employment for Cause in accordance with the following provisions:

(i) **Termination for Cause Prior to a Change in Control**. Prior to the date of a Change in Control, the Company shall be deemed to have "Cause" to terminate the Executive's employment hereunder only upon the Executive's:

(1) failure to comply with any material term of this Agreement, or to perform and discharge the duties or obligations of the Executive's office, or such other duties as may from time to time be assigned to the Executive by, or at the direction of, the Board, faithfully, diligently, and competently, unless any such failure is cured in all material respects to the reasonable satisfaction of the Board within sixty (60) days after the Executive receives written notice of such failure; or

(2) failure to devote substantially all of his working time and efforts to the business and affairs of the Company unless any such failure is cured in all material respects to the reasonable satisfaction of the Board within sixty (60) days after the Executive receives written notice of such failure; or

(3) misconduct that is demonstrably injurious to the interests of the Company, Avangrid Networks, Inc. or any of their respective Affiliates (as that term is defined in Section 9) unless such misconduct is rectified in all material respects to the reasonable satisfaction of the Board within thirty (30) days after the Executive receives written notice of such misconduct; or

(4) commission of a serious crime, such as an act of fraud, misappropriation of funds, embezzlement, or a crime involving personal dishonesty or moral turpitude.

(ii) **Termination for Cause After a Change in Control**. During the period that commences on a Change in Control and for twenty-four (24) months thereafter (the "Change in Control Protective Period"), and subject to the same notice and cure provisions specified above, the Company (or its successor or other entity employing the Executive following such Change in

Control) shall be deemed to have Cause to terminate the Executive's employment hereunder only upon the Executive's:

(1) commission of a serious crime, such as an act of fraud, misappropriation of funds, embezzlement, or a crime involving personal dishonesty or moral turpitude; or

(2) misconduct that is demonstrably injurious to the interests of the Company, Avangrid Networks, Inc. or any of their respective Affiliates; or

(3) willful failure of the Executive to substantially perform his duties (other than by reason of incapacity due to physical or mental illness or injury).

(c) **Termination by Company without Cause**. The Company may terminate the Executive's employment at any time, without cause, upon ninety (90) days prior written notice to the Executive.

(d) **Termination by Executive**.

(i) **Breach by the Company, not during Change of Control Protective Period**. If the Executive is not in default of any of the Executive's obligations under Section (2), (9), (10) or (11) hereof, the Executive may terminate employment hereunder on account of a Constructive Termination in accordance with this Section (5)(d)(i). For purposes of this Agreement, a Constructive Termination means:

(1) a Separation from Service (defined as a Separation from Service within the meaning of Code §409A and related regulations) within ninety (90) days of the initial occurrence of one of the following events arising without the consent of the Executive (a "Constructive Termination Event"):

(A) A material diminution in the Executive's annual base salary rate, unless such reduction is part of, and consistent with, a general reduction of the compensation rates of all employees of the Company or of the Executive's business unit;

(B) Except as provided in Section (2)(b), a material diminution in the Executive's authority, duties, or responsibilities, including the assignment of duties materially inconsistent in any adverse respect with such Executive's position, duties, responsibilities and status with the Company immediately prior thereto, or diminishment in such Executive's management responsibilities, duties or powers as in effect immediately prior thereto, or the removal from or failure to re-elect such Executive to any such position or office;

(C) A requirement that the Executive relocate his principal place of employment by more than fifty (50) miles from the Company's current executive offices in Orange, Connecticut; or

(D) Any other action or inaction that constitutes a material breach by the Company of the Agreement, including (1) a failure to include the Executive in the management salary compensation programs then in effect on substantially the same terms and conditions as that applicable to the other officers or similarly situated executives of the Company; (2) a failure to continue the Executive's participation in the material benefit plans of the Company on substantially the same basis, both in terms of the amount of benefits provided (other than due to the Company's stock price performance, provided such performance is a relevant criterion in determining the amount of benefits) and the level of the

Executive's participation relative to other officers or similarly situated executives of such Company, as that in effect immediately prior thereto; or (3) a failure to renew this Agreement at the time such Agreement expires, provided that the Executive was willing and able to execute a new Agreement providing terms and conditions substantially similar to those in the expiring Agreement and to continue working for the Company; and

(2) The Executive has given notice to the Board stating that in the Executive's opinion at least one of the Constructive Termination Events has occurred and setting forth in reasonable detail the relevant facts, and such notice was given within thirty-one (31) days of the occurrence of the Constructive Termination Event; and

(3) The Company shall have failed to remedy or otherwise cure the situation within thirty-one (31) days after receipt of the notice.

(ii) Breach by the Company, during Change of Control Protective Period. If the Executive is not in default of any of the Executive's obligations under Section (2), (9), (10) or (11) hereof, the Executive may terminate employment hereunder on account of a Constructive Termination as defined herein so long as the Executive's Separation from Service occurs within 90 days of the initial occurrence of the Constructive Termination Event and until the Separation from Service, the Executive was willing and able to continue working for the Company and the Company did not have grounds to terminate the Executive's employment for Cause.

(iii) In the absence of Breach by the Company. If the Executive is not in default of any of the Executive's obligations under Section (2), (9), (10) or (11) hereof, the Executive may terminate employment in the absence of a Breach by the Company, effective upon at least ninety (90) days prior written notice.

(e) **Date of Termination**. For purposes of this Agreement, the "Date of Termination" is defined as (i) the Executive's date of death, in the event of his death; or the date of his termination due to disability, in the case of disability, or (ii) the date specified in the notice of termination, in the case of the Executive's termination pursuant to Sections (5)(b), (5)(c), 5(d) hereof.

(6) CONSEQUENCES OF TERMINATION OR NON-RENEWAL.

(a) **Termination on Death or Disability; or by the Executive in the Absence of a Breach by the Company**. If the Executive's employment terminates by reason of the Executive's death, or in the event that the Executive's employment is terminated due to total or partial physical or mental disability such that the Executive becomes entitled to long-term disability benefits under the Company's long-term disability plan, or if the Executive terminates employment hereunder in the absence of a Breach by the Company upon ninety (90) days prior written notice, the Company shall pay to the Executive or, in the event of death or disability, the Executive's personal representative and/or spouse:

(i) the Executive's Base Salary, earned but unpaid as of the Date of Termination, and Accrued Incentive Compensation (as defined in Section 4(b));

(ii) Stub-Period Incentive Compensation (as defined in Section 4(b)) earned, but unpaid, as of the Date of Termination, but only in the case of the Executive's death or termination due to disability, and not in the case of his voluntary termination; plus

(iii) any amounts payable pursuant to (4)(d) (unreimbursed business expenses), (4)(e) (employee benefits due and owing), and 4(f) (accrued, but unpaid vacation or holidays); plus

(iv) any benefits or amounts payable, on account of the Executive’s (A) exercise of his then exercisable rights under any long-term incentive compensation plan or arrangement, and (B) participation in any deferred compensation plan in which he was a participant as of his termination of service.

Pending a determination that the Executive is entitled to long-term disability benefits, the Executive’s short-term disability benefits shall be extended, as necessary at 50% of Base Salary, if his length of employment with the Company is of such short duration that his short term disability benefits would otherwise expire before his entitlement to long-term disability benefits is determined.

Upon payment of these amounts, the Company shall have no further obligation to the Executive, the Executive’s personal representative and/or spouse under this Agreement or on account of, or arising out of, the termination of the Executive’s employment.

(b) **Upon Termination for Cause; or by the Executive on fewer than 90 day’s notice**. If the Company terminates the Executive’s employment for Cause, or the Executive terminates employment hereunder in the absence of a Breach by the Company and upon fewer than ninety (90) days prior written notice, the Company shall pay to the Executive:

(i) the Executive’s Base Salary earned, but unpaid, as of the Date of Termination; plus

(ii) any amounts payable pursuant to Sections (4)(d), (4)(e), and 4(f) hereof, and

(iii) any benefits payable under any elective non-qualified deferred compensation plan in which the Executive had been a participant, other than any benefit under the UI SERP or any other supplemental executive retirement plan of the Company or an Affiliate, whereupon the Company shall have no further obligation to the Executive under this Agreement or on account of, or arising out of, the termination of the Executive's employment.

(c) **Upon Termination Without Cause or a Constructive Termination prior to a Change in Control**. If the Company terminates the Executive's employment hereunder without Cause or if the Executive terminates the Executive's employment hereunder on account of a Constructive Termination, and in either case the termination constitutes an Involuntary Separation from Service within the meaning of Treasury Regulations Section 1.409A-1(n) and is not upon a Change in Control or within the Change in Control Protective Period, the Company shall pay or provide (as applicable) to the Executive, all of the following:

(i) the Executive's Base Salary, Accrued Incentive Compensation and Stub-Period Incentive Compensation earned, but unpaid, as of the Date of Termination; plus

(ii) any amounts payable pursuant to Sections 4(d), 4(e), and 4(f); plus

(iii) any benefits or amounts payable, on account of the Executive's (A) exercise of his then exercisable rights under any long-term incentive compensation plan or arrangement, and (B) participation in any deferred compensation plan in which he was a participant as of his termination of service; plus

(iv) a lump sum severance payment in an amount equal to the product of 1/12 of the Executive's Base Salary rate approved by the Board at the time of its most recent review of the salary rates of all of the Company's executives, plus 1/12 of the short-term annual incentive compensation payment to which the Executive would be entitled, calculated as if he had been employed by the Company on the last day of the year of his termination, as if both personal goals and Company goals had been achieved ‘at Target’, multiplied by the number of whole and partial years of the Executive's service as an Employee of the Company at termination (not to be less than

12 nor more than 24 years), which the parties agree would be 24 years given the Executive’s length of service.

(v) benefits under the Company's health care plans during the COBRA continuation period on the same terms as are then available to active employees of the Company.

(d) **Separation from Service**. Notwithstanding anything herein to the contrary, no compensation constituting severance or deferred compensation shall be paid under the Agreement upon a termination of employment or termination of service unless such termination of employment or termination of service constitutes a Separation from Service as defined herein.

(e) **Timing of Payment**. Any cash amount that is due and owing to the Executive upon a termination of service pursuant to Section (6) or Section (7) will be paid on the thirtieth (30th) day following the Executive's Separation from Service and in no event may the Executive designate the timing or year of payment. Notwithstanding the foregoing, however, (i) any Stub-Period Incentive Compensation shall be calculated in accordance with the terms of the applicable plan or program and such incentive compensation and that portion of any severance payment that is based on such incentive compensation shall be paid at the same time that such incentive compensation generally would be payable to all other employees, but in no event later than March 15th of the calendar year following the end of the performance period to which such incentive compensation relates; (ii) any long-term incentive compensation shall be calculated in accordance with the terms of the applicable plan or program and such incentive compensation shall be paid at the same time that such incentive compensation generally would be payable to all other employees, but in no event later than March 15th of the calendar year following the end of the performance period to which such compensation relates; and (iii) any qualified or non-qualified deferred compensation payable pursuant to the terms of a plan of the Company shall be paid in accordance with the terms of the applicable plan.

(f) **Release**. All payments and obligations of the Company under Section (6) and (7) shall be conditioned upon the execution and delivery by Executive to the Company of a full and effective release by Executive of any liability by the Company to Executive in form and substance reasonably satisfactory to the Company.

(7) CHANGE IN CONTROL

(a) If on, or within twenty-four (24) months following, a Change in Control, the Company (or its successor or other entity employing the Executive following such Change in Control) either terminates the Executive's employment hereunder without Cause or fails to renew this Agreement on substantially identical terms, or if the Executive terminates the Executive's employment on account of a Constructive Termination (as defined herein), and in any such case the termination constitutes an Involuntary Separation from Service within the meaning of Treasury Regulations Section 1.409A-1(n), then the Executive shall be entitled to the following:

(i) the Executive's Base Salary, Accrued Incentive Compensation and Stub-Period Incentive Compensation earned, but unpaid, prior to the Date of Termination; plus

(ii) any amounts payable pursuant to Sections 4(d), 4(e), and 4(f) hereof; plus

(iii) any benefits or amounts payable, on account of the Executive's (A) exercise of his then exercisable rights under any long-term incentive compensation plan or arrangement, and (B) participation in any deferred compensation plan in which he was a participant as of his termination of service.

(b) For purposes of this Agreement, Change in Control shall mean "Change in Control" as defined in Section 4(c) of this Agreement.

(c) During the Change in Control Protective Period, the Executive's Base Salary may not be reduced to an annual rate less than the Base Salary rate fixed by the Board as a result of its most recent review of salary rates, unless such reduction is part of, and consistent with, a general reduction of the compensation rates of all employees of the Company, its successor, or purchaser of assets, as the case may be.

(d) Payment of benefits under this Section 7 shall be subject to, and conditioned upon, the provisions of Section 6(e) and (f) hereof.

(8) RESERVED FOR FUTURE USE

(9) CONFIDENTIAL INFORMATION

The Executive recognizes that the Executive's employment by the Company is one of highest trust and confidence by reason of his access to certain trade secrets, confidential business practices, and proprietary information concerning the Company or any person or entity that directly, or indirectly through one or more intermediaries, controls or is controlled by, or is under common control with, the Company (an "Affiliate"), including, without limitation, the Company's methods of doing business, marketing and strategic business plans, employees' compensation and contract terms, customer lists and customer characteristics (collectively referred to as "Proprietary Information"). The Executive agrees and covenants to exercise utmost diligence to protect and safeguard the trade secrets, confidential business practices and Proprietary Information concerning the Company and any Affiliate. The Executive further agrees and covenants that, except with the prior written consent of the Company, he will not, either during the Term hereof or thereafter, directly or indirectly, use for his own benefit or for the benefit of any other person or organization, or disclose, disseminate or distribute to any other person or organization, any of the Proprietary Information (whether or not acquired, learned, obtained or developed by the Executive alone or in conjunction with another), unless and until such Proprietary Information has become a matter of public knowledge through no action or fault of the Executive or unless otherwise required by court order to comply with legal process. All memoranda, notes, records, drawings, documents or other writings whatsoever made, compiled, acquired or received by the Executive during the Term hereof arising out of, in connection with, or related to any activity or business of the Company are and shall continue to be the sole and exclusive property of the Company, and shall, together with all copies thereof, be returned and delivered to the Company by the Executive immediately, when he ceases to be employed by the Company, or at any other time upon the Company's demand.

(10) NON-COMPETITION

The Executive agrees and covenants that, during the Term of this Agreement and for a period of twelve (12) months following the month during which the Executive ceases to be employed by the Company, the Executive will not, in any capacity, directly or indirectly, whether as a consultant, employee, officer, director, partner, member, principal, shareholder, or otherwise:

(a) compete with the Company in the marketing of energy services related to the delivery or use, at retail, of electricity in the Company's franchise territory; or

(b) engage in any business activity that would, directly or indirectly, diminish the retail sales of electricity in the Company's franchise territory; expressly provided, however that nothing herein shall be construed to prevent the Executive from being employed by, or becoming a consultant to, an entity that engages in energy conservation and load management programs and services as a contractor or subcontractor of the Company; or

(c) directly or indirectly divert or attempt to divert from the Company or any Affiliate any business in which such entity has been actively engaged during the Term hereof, or in any way interfere with the relationships that the Company or any Affiliate has with its customers or sources of supply; or

(d) directly or indirectly interfere or attempt to interfere with the relationship between the Company or any Affiliate and any of such entity's employees, unless the Company has granted prior written approval which may be withheld for any reason. Nothing in this Section shall be construed to prohibit the ownership by the Executive of less than five percent (5%) of any class of securities of any entity that is engaged in any of the foregoing businesses having a class of securities registered pursuant to the Securities Exchange Act of 1934 (the "Exchange Act"), provided that such ownership represents a passive investment and that neither the Executive, nor any group of persons including the Executive, in any way, directly or indirectly, manages or exercises control of such entity, guarantees any of its financial obligations, or otherwise takes any part in its business, other than through exercising the Executive's rights as a shareholder.

For purposes of this Section "Affiliate" means any entity that directly or indirectly controls, is controlled by, or is under common control with the Company.

As used in Sections 9-11, the term the "Company" shall include Avangrid Service Company, its affiliates, its parent and any of their respective affiliates, subsidiaries, assigns, or successors to, or acquirers of, the business or assets of the Company.

(11) DISCLOSURE AND ASSIGNMENT OF INVENTIONS AND DISCOVERIES

(a) **Disclosure of Inventions**. The Executive agrees to make prompt and complete disclosure to the Company of all inventions and discoveries made or conceived by him, alone or with others, while this Agreement is in effect, or within a reasonable time thereafter, which arise out of or relate to the services rendered pursuant to this Agreement. The Executive also agrees to keep necessary records, including notes, sketches, drawings, models and data supporting all such inventions and discoveries made by him, alone or with others, during the course of performing the services pursuant to this Agreement, and the Executive agrees to furnish the Company, upon request, all such records.

(b) **Assignment of Inventions and Discoveries**. The Executive also agrees that he will assign to the Company all inventions and discoveries made by him which arise out of and pertain to the services rendered pursuant to this Agreement, together with all domestic and foreign patents as may be obtained on these inventions and discoveries. The Executive further agrees that, upon request of the Company, he will execute all necessary papers and cooperate in the fullest degree with the Company in securing, maintaining and enforcing any such patents which arise out of his services under this Agreement. It is understood, however, that these obligations undertaken by Executive will be at no expense to him.

(12) MISCELLANEOUS.

(a) **Equitable Remedies**. The Executive acknowledges that the restrictions provided for in Sections (9) through (11) are reasonable and necessary in order to protect the legitimate interests of the Company and its Affiliates; and that any violation thereof would result in serious damage and irreparable injury to the Company and its Affiliates. Further, the Executive acknowledges that the services to be rendered by him are of such unique and extraordinary nature, and the resulting injury to the Company from a breach of Sections (9) through (11), inclusive, by the Executive would be of such a nature, that an action at law for the collection of damages would not provide adequate relief to the Company for the enforcement of its rights in the event of an actual or threatened violation by the Executive of his commitments and obligations under Sections (9) through (11). The Executive agrees that upon the actual or threatened breach or violation of any of the commitments under Section (9) through (11), the Company shall be entitled to both preliminary and permanent injunctive relief, in any action or proceeding brought in an appropriate court having jurisdiction over the Executive, to restrain him from committing any violation of any such commitments and obligations.

(b) **Effect Of Breach**. All payments and other benefits payable but not yet distributed to Executive under Sections (6) or (7) shall be forfeited and discontinued in the event that the Executive violates Sections (9) through (11) of this Agreement, or willfully engages in conduct which is materially injurious to the Company, monetarily or otherwise, all as determined in the sole discretion of the Company.

(c) **<u>Successors; Binding Agreement; Assignment</u>**.

(i) The Company will require the acquirer of all or substantially all of the business or assets of the Company (whether directly or indirectly, by purchase of stock or assets, merger, consolidation or otherwise), by agreement in form and substance reasonably satisfactory to the Executive, to expressly assume and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place. As used in this Section, the term the “Company” shall include Avangrid Service Company, and any successor to, or acquirer of, the business or assets of the Company that executes and delivers the agreement provided for in this Section (12)(c) or which otherwise becomes bound by all the terms and provisions of this Agreement by operation of law.

(ii) This Agreement, and the Executive's rights and obligations hereunder, may not be assigned by the Executive. Any attempted assignment of this Agreement by the Executive shall be void and of no force and effect. This Agreement and all rights of the Executive hereunder shall inure to the benefit of and be enforceable by the Executive's personal or legal representatives, executors, administrators, successors, heirs, distributees, devisees and legatees.

As used in this Section, the term the "Company" shall include Avangrid Service Company, and any successor to, or acquirer of, the business or assets of the Company that executes and delivers the agreement provided for in this Section (12)(c) or which otherwise becomes bound by all the terms and provisions of this Agreement by operation of law.

(d) **<u>Notices</u>.** For the purpose of this Agreement, notices and all other communications to either party hereunder provided for in the Agreement shall be in writing and shall be deemed to have been duly given when delivered or mailed by United States certified or registered mail, return receipt requested, postage prepaid, addressed, in the case of the Company, to the Secretary of the Company at 180 Marsh Hill Road, Orange, CT 06477, or, in the case of the Executive, to the Executive at his residence, or to such other address as either party shall designate by giving written notice of such change to the other party.

(e) **<u>Waiver; Amendment</u>**. No provision of this Agreement may be modified, waived or discharged unless such waiver, modification or discharge is approved by the Board and agreed to in a writing signed by the Executive and the Company. No waiver by either party hereto at any time of any breach by the other party hereto of, or compliance with, any condition or provision of this Agreement to be performed by such other party shall be deemed a waiver of any similar or dissimilar provisions or conditions at the same or at any prior or subsequent time. No agreements or representations, oral or otherwise, express or implied, with respect to the subject matter hereof have been made by either party that are not set forth expressly in this Agreement.

(f) **<u>Governing Law; Severability</u>**. The validity, interpretation, construction and performance of this Agreement shall be governed by the laws of the State of Connecticut. The validity or unenforceability of any provision or provisions of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement, which shall remain in full force and effect. In the event one or more of the provisions of this Agreement should, for any reason, be held to be invalid, illegal or unenforceable in any respect, the parties agree that such provisions shall be legally enforceable to the extent permitted by applicable law, and that any court of competent jurisdiction shall so enforce such provision, or shall have the authority hereunder to modify it to make it enforceable to the greatest extent permitted by law.

(g) **<u>Code Section 409A Compliance</u>**. The parties hereto recognize that certain provisions of this Agreement may be affected by Section 409A of the Code and guidance issued thereunder, and agree to amend this Agreement, or take such other action as may be necessary or advisable, to comply with Section 409A. It is intended that all payments hereunder shall comply with Section 409A and the regulations promulgated thereunder so as to not subject the Executive to payment of interest or any additional tax under Section 409A. In furtherance thereof, if payment or provision of any amount or benefit hereunder that is subject to Section 409A at the time specified herein would subject such amount or benefit to any additional tax under Section 409A, the payment or provision of such amount or benefit shall be postponed to the earliest date on which the payment or provision of such amount or benefit could be made without incurring such additional tax. In addition, to the extent that any regulations or other guidance issued under Section 409A (after application of the previous provisions of this Section (12)G)) would result in the Executive's being subject to the payment of interest or any additional tax under Section 409A, the parties agree, to the extent reasonably possible, to amend this Agreement in order to avoid the imposition of any such interest or additional tax under Section 409A, which amendment shall have the minimum economic effect necessary and be reasonably determined in good faith by the Company and the Executive.

Notwithstanding anything herein to the contrary, it is expressly understood that at any time the Company (or any related employer treated with the Company as the service recipient for purposes of Code Section 409A) is publicly traded on an established securities market (as defined for purposes of Code Section 409A), if a payment or provision of an amount or benefit constituting a deferral of compensation is to be made pursuant to the terms of this Agreement to the Executive on account of a Separation from Service (as defined herein) at a time when the Executive is a Specified Employee (as defined for purposes of Code Section 409A(a)(2)(B)(i)), such deferred compensation shall not be paid to the Executive prior to the date that is six (6) months after the Separation from Service. In the event this restriction applies, the deferred compensation that the Executive would have otherwise been entitled to during the restriction period will be accumulated and paid (without adjustment for the delay in payment) on the first business day of the seventh month following the date of the Executive's Separation from Service.

The parties hereto intend that the Agreement, as amended, be consistent with IRS Notice 2007-78, IRS Notice2007-86 and other Code Section 409A transition relief, and it shall be interpreted accordingly.

(h) **No Conflict**. The Executive hereby represents and warrants to the Company that neither the execution nor the delivery of this Agreement, nor the employment of the Executive by the Company will result in the breach of any agreement to which the Executive is a party.

(i) **Survival**. The provisions of this Agreement shall not survive the termination of this Agreement or of the Executive's employment hereunder, except that the provisions of Sections (6) through (12) hereof shall survive such termination and shall be binding upon the Executive, the Executive's personal representative and/or spouse, the Company, and the Company's successors and assigns.

(j) **Counterparts; Facsimile Execution**. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument. Facsimile execution and delivery of this Agreement is legal, valid and binding execution and delivery for all purposes.

(k) **Entire Agreement.** This Agreement contains the entire agreement and understanding between the parties hereto in respect of Executive's employment and supersedes, cancels and annuls any prior or contemporaneous written or oral agreements, understandings, commitments and practices between them respecting Executive's employment except as specifically referenced herein.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

AVANGRID SERVICE COMPANY

Date: May 4, 2020

/s/ Peter Church
Peter Church
Chief Human Resources Officer

EXECUTIVE

Date: May 4, 2020

/s/ Anthony Marone, III
Anthony Marone, III

EXHIBIT 21.1

LIST OF SUBSIDIARIES OF Avangrid, Inc.

Name of Subsidiary	State or Jurisdiction of Incorporation Or Organization
Avangrid Networks, Inc.(1)*	Maine
New York State Electric & Gas Corporation(2)	New York
Rochester Gas and Electric Corporation(2)	New York
Central Maine Power Company(2)	Maine
Maine Natural Gas Corporation(2)	Maine
UIL Holdings Corporation(2)	Connecticut
The United Illuminating Company(4)	Connecticut
The Southern Connecticut Gas Company(4)	Connecticut
Connecticut Natural Gas Corporation(4)	Connecticut
The Berkshire Gas Company(4)	Massachusetts
Avangrid Renewables Holdings, Inc.(1)*	Delaware
Avangrid Renewables, LLC(3)	Oregon

(1) Subsidiary of Avangrid, Inc.
(2) Subsidiary of Avangrid Networks, Inc.
(3) Subsidiary of Avangrid Renewables Holdings, Inc.
(4) Subsidiary of UIL Holdings Corporation

* Holding Company

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Avangrid, Inc.:

We consent to the incorporation by reference in the registration statement (No. 333-231251) on Form S-3 and registration statements (No. 333-212616 and No. 333-208571) on Form S-8 of Avangrid, Inc. of our reports dated March 1, 2021, with respect to the consolidated balance sheets of Avangrid, Inc. as of December 31, 2020 and 2019, the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (and financial statement schedule I), and the effectiveness of internal control over financial reporting as of December 31, 2020, which reports appear in the December 31, 2020 annual report on Form 10-K of Avangrid, Inc.

/s/ KPMG LLP

New York, New York
March 1, 2021

EXHIBIT 31.1

CERTIFICATION

I, Dennis V. Arriola, certify that:

1. I have reviewed this annual report on Form 10-K of Avangrid, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2021

/s/ Dennis V. Arriola

Dennis V. Arriola
Director and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Douglas K. Stuver, certify that:

1. I have reviewed this annual report on Form 10-K of Avangrid, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2021

/s/ Douglas K. Stuver

Douglas K. Stuver
Chief Financial Officer

EXHIBIT 32

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Pursuant to 18 U.S.C. 1350, the undersigned, Dennis V. Arriola and Douglas K. Stuver, the Chief Executive Officer and Chief Financial Officer, respectively, of Avangrid, Inc. (the "issuer"), do each hereby certify that the report on Form 10-K to which this certification is attached as an exhibit (the "report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)) and that information contained in the report fairly presents, in all material respects, the financial condition and results of operations of the issuer.

/s/ Dennis V. Arriola

Dennis V. Arriola
Director and Chief Executive Officer
Avangrid, Inc.
March 1, 2021

/s/ Douglas K. Stuver

Douglas K. Stuver
Chief Financial Officer
Avangrid, Inc.
March 1, 2021

Emond, Gary

To: townwhitefieldadm@gmail.com
Subject: Central Maine Power Company Section 3027 Transmission Line Project - CMP Application and Informational Filing

All,

As requested by the Whitefield Planning Board on the evening of May 19, 2021, attached is CMP application and informational filing as one PDF that can be posted to the Whitefield website. This PDF includes::

- The original CMP application to the Town of Whitefield;
- A copy of this email;
- A commitment letter from CMP and associated map depicting proposed fiber optic splice box locations, and a schematic showing where these splices could be located on transmission line poles; and
- A list of roads in Whitefield that could be used by CMP to access their transmission line ROW during construction.

Please contact us if you have any questions or need more information. We look forward to discussing the Section 3027 project with you again during the upcoming planning board meeting on June 16.

Regards,

Gary Emond
Environmental Project Manager

POWER Engineers, Inc.
303 U.S. Route One, Suite 2A
Freeport, ME 04032
Direct: (207) 869-1247
Cell: (207) 441-3873
Fax: (207) 869-1299

CENTRAL MAINE POWER

Thorn C. Dickinson
Vice President Business Development

January 18, 2019

Louis D. Sell
Chair, Whitefield Economic Development Committee
571 East River Road
Whitefield, Maine 04353

Dear Louis,

We really enjoyed the opportunity to meet with you and the Whitefield Economic Development Committee and we appreciate your letter summarizing our discussion and the presentation of the needs of your Committee. We echo your desire to work together to explore additional benefits and value that our proposed transmission line Section 3027, part of the New England Clean Energy Connect project, could bring to your community.

As we discussed in our meeting, we are committed to install spare fibers in optical ground wire in the proposed Section 3027 transmission line that could be utilized for “middle mile” communication transport to the Whitefield area. These spare fibers in the optical ground wire can be used for many types of communication transport, including broadband internet and cellular phone.

In addition to our commitment to install spare fibers, we have evaluated your requested splice locations discussed verbally in the meeting on December 12, 2018 and noted in your letter dated December 18, 2018. We are happy to confirm that we will locate a splice enclosure at all your requested road crossings: Route 17, Route 126, Route 194, and Route 218. In addition, we intend to locate a splice enclosure near Route 1 in Wiscasset, Maine where the line will intersect the existing Maine Fiber Company’s “3 Ring Binder” fiberoptic infrastructure. We have enclosed a map depicting these proposed splice locations, see Enclosure 1, and conceptual attachment details depicting how a communications provider might interconnect to our proposed transmission line fiber splice enclosure, see Enclosure 2.

We hope that with our written commitment, you will be successful in securing enhanced communications infrastructure in your community.

Warm Regards,

Thorn C Dickinson

Thorn Dickinson
Vice President, Business Development

Enclosures:

Enclosure 1- NECEC Section 3027 Whitefield Area Fiber Splice Map
Enclosure 2- NECEC Section 3027 Conceptual ADSS Attachment


NECEC Section 3027
Proposed Whitefield Area Fiber Splices
N
Coopers Mills Substation
Splice 1- RT 17
Splice 2- RT 126
Splice 3- RT 194
Splice 4 - RT 218
Splice 5- RT 1 3 Ring Binder
Maine Yankee Substation
Windsor
Augusta
Gardiner
Jefferson
Washing
Waldobor
Newcastle
Wiscasset
Bristol
N Belfast Ave
Water St
Togus Rd
Rockland Rd
Jefferson Rd
E Pittston Rd
River Ave
Wiscasset Rd
Pittston Rd
Washington Rd
Alna Rd
Gardiner Rd
Bremen Rd
Waldoboro Rd
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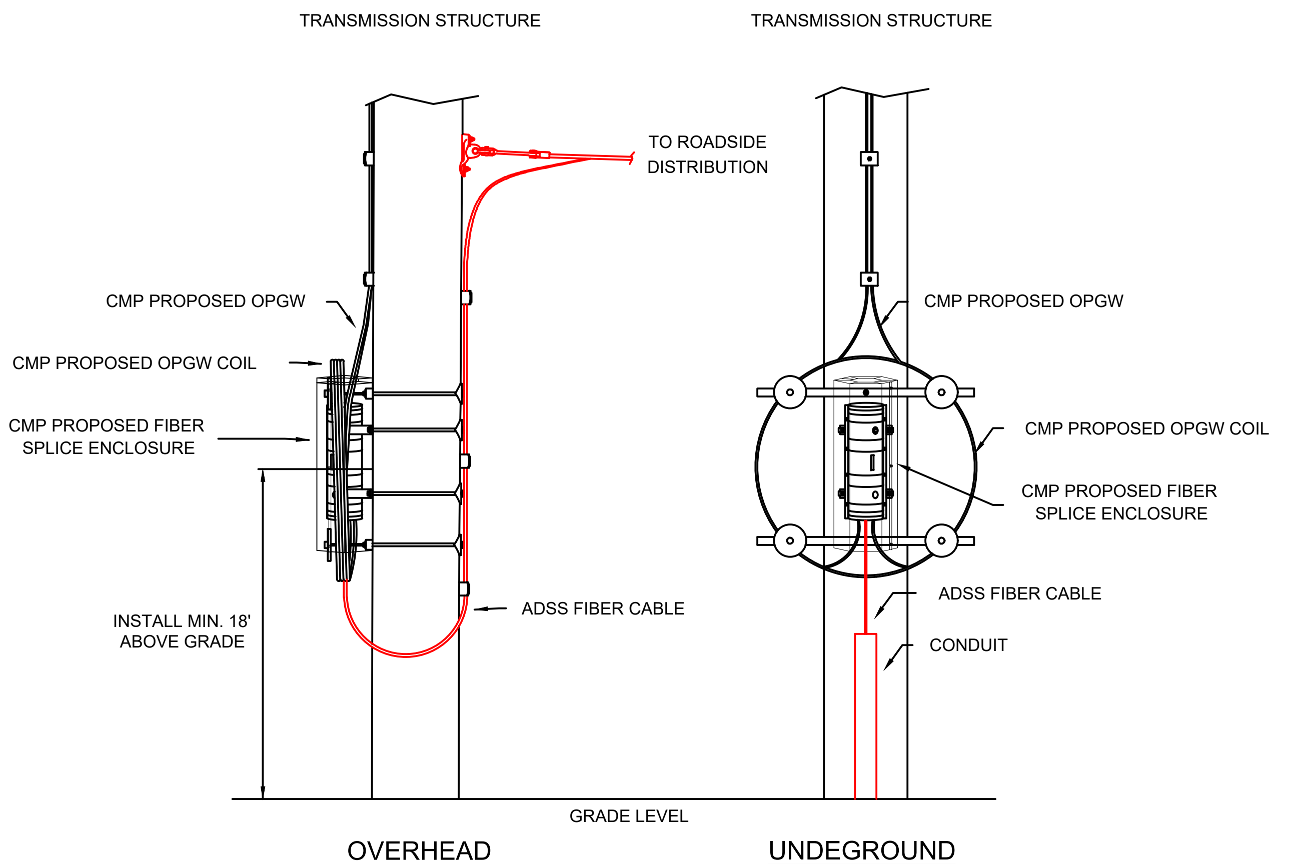

LEGEND

CMP INSTALLED

BY OTHERS

OPGW OPTICAL GROUND WIRE (FIBER CABLE)

ADSS ALL-DIELECTRIC SELF-SUPPORTING (FIBER CABLE)

CMP AVANGRID

SECTION 3027
CONCEPT ADSS ATTACHMENT
NECEC PROJECT

REV	DESCRIPTION	DATE	BY	CK	APP
0	CONCEPT SKETCH ISSUED	01/16/19	JMT		

BY	JMT	SCALE: NTS	FILE: 3027-SK1.dwg
CK		NO. 3027-SK1	REV 0
APP			
DATE:	01/16/19		

REV DESCRIPTION DATE BY CK APP

INFO

LOGO

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CMP Section 3027

As requested by the Whitefield Planning Board on May 19, 2021, below is a list of existing roads that lead to the Section 3027 right-of-way. These are listed from north to south.

1. Doyle Road
2. Devine Road
3. Cooper Road
4. Route 126 (Gardiner Road)
5. Philbrick Lane
6. Route 194 (Pittston Road)
7. Route 218 (Wiscasset Road)