SECTION D – FEDERAL OIL AND GAS LEASING AVAILABILITY

INTRODUCTION

This section of the Final EIS identifies George Washington National Forest lands that could be made available for oil and gas leasing, in accordance with the Mineral Leasing Act, under various leasing alternatives. It also describes the affected environment and discusses reasonably foreseeable impacts of oil and gas activities on the environment resulting from each leasing alternative. Oil and gas leasing is identified as a significant issue in Chapter 1 of the Final EIS. Issues and concerns expressed by the public and government agencies during the public comment period for this EIS have been addressed by the analysis. Additional discussion of specific concerns with gas development is in FEIS, Appendix I-Analysis of Concerns and Risks of Horizontal Drilling and Hydraulic Fracturing.

Management of the federal leasable oil and gas resources is a shared responsibility between the Forest Service and the U.S. Department of Interior. The Bureau of Land Management (BLM) has a major role in issuing and supervising operations on licenses, permits, and leases for federal leasable minerals. BLM cannot issue oil and gas leases for lands administered by the Forest Service without consent from the Secretary of Agriculture. As the agency responsible for federal oil and gas lease issuance and administration, the BLM participated in this EIS as a cooperating agency. This analysis will be used by both agencies as the basis for making oil and gas leasing decisions under their authorities. The responsible officials of the Forest Service and BLM may release separate Records of Decision. The Forest Service decision identifies which lands will be administratively available for oil and gas leasing along with associated conditions and lease stipulations. The BLM decision determines whether oil and gas leases will be issued on the administratively available lands.

If BLM issues any leases on the lands administratively available, the leaseholder cannot construct a road, drill a well, or conduct ground disturbing operations until the federal government (Forest Service and BLM) reviews and approves plans for each proposed well, road, and associated facilities. Before ground disturbing operations can occur, the leaseholder must submit for review and approval an Application for Permit to Drill (APD) that includes a Drilling Plan and a Surface Use Plan of Operations. The Forest Service would be the lead agency and BLM a cooperating agency for environmental analysis (NEPA) for the federal decision on the APD proposed operations on NFS lands. The Forest Service decision would involve approval of the Surface Use Plan of Operations. The BLM decision would involve approval of the entire APD.

Thus, there are two stages of federal oil and gas decisions, with each stage requiring decisions by two agencies (Forest Service and BLM). The first stage is the leasing availability decision; the second stage is the Application for Permit to Drill (APD) decision. This EIS is for the leasing decision and includes environmental protection requirements and mitigating measures that would be implemented at the second stage (APD). The site-specific environmental analysis at the second stage would tier to this EIS.

LEGISLATION AND POLICY RELATING TO OIL AND GAS

The Mineral Leasing Act of 1920 (as amended)

The Mineral Leasing Act of 1920, as amended, authorizes and governs oil and gas leasing on lands with federal oil and gas rights. The primary authority and responsibility for determinations regarding leasing remains with the Secretary of the Interior and the BLM. The Act makes deposits of oil and gas on federal lands available for oil and gas leasing, unless a specific land order has been issued to close an area. The Act also mandates that oil and gas surface-disturbing activities be regulated and reclamation procedures developed for the conservation of surface resources.

The Mineral Leasing Act for Acquired Lands of 1947

The Mineral Leasing Act for Acquired Lands of 1947 states that all deposits of coal, phosphate, oil, oil shale, gas, sodium, potassium, and sulfur that are owned or may be acquired by the US and that are within lands acquired by the US may be leased by the Secretary of the Interior under the same conditions as contained in the leasing provisions of the mineral leasing laws. No mineral deposits shall be leased without the consent of the head of the executive department having jurisdiction over the lands containing the deposit and subject to such conditions as that official may prescribe.

The Mining and Minerals Policy Act of 1970

The Mining and Minerals Policy Act of 1970 indicates that the continuing policy of the federal government is to foster and encourage private enterprise in the development of economically sound and stable domestic mining and minerals industries and the orderly and economic development of domestic mineral resources.

The Energy Security Act of 1980

The Energy Security Act of 1980 directs the Secretary of Agriculture to process applications for leases and permits to explore, drill, and develop resources on National Forest System lands, notwithstanding the current status of any management plan being prepared.

The Federal Onshore Oil and Gas Leasing Reform Act of 1987

The Leasing Reform Act amended the Mineral Leasing Act of 1920. It provides the Forest Service with more input on oil and gas leasing on National Forest System lands. Under the Leasing Reform Act, Forest Service consent is required before BLM can lease National Forest System lands. Forest Service 36 CFR 228 subpart E Oil and Gas Resources regulations, issued in 1990, established 1) the process for making oil and gas leasing decisions in accordance with the Leasing Reform Act, and 2) requirements for Surface Use Plan of Operations and inspection and compliance.

Bureau of Land Management (BLM) Regulations and Forest Service Oil and Gas Regulations

BLM regulations (43 CFR Part 3100) and Forest Service regulations (36 CFR Subpart 228E) describe the procedures by which each agency will carry out its statutory responsibilities in the issuance of oil and gas leases and in subsequent operations (Application for Permit to Drill (APD)). The BLM is responsible for offering and issuing leases and for authorizing and administering subsequent operations to explore and develop oil and gas (APD: Drilling Plan and Surface Use Plan of Operations). Title 43 CFR Subpart 3160 provides regulations for onshore oil and gas operations, including, inspection and enforcement. The Forest Service regulations prescribe methods by which the Forest Service will make decisions with regard to lands administratively available for oil and gas leases and subsequent management of oil and gas operations. The Forest Service determines which National Forest System lands are available for oil and gas leasing, and the specific lands which the BLM may offer for lease; prescribes constraints, including any Stipulations, that provide reasonable protection to surface resources; approves Surface Use Plan of Operations (SUPO); and inspects and insures compliance with the surface use requirements of the leases and operating plans.

Forest Service Strategic Plan for Fiscal Years 2007-2012

The Government Performance and Results Act of 1993 requires the Forest Service to prepare a Strategic Plan at the National level. As part of Goal (2) of the Strategic Plan for Fiscal Years 2007-2012 (to Provide and Sustain Benefits to the American People), Objective 2.3 is to help meet energy resource needs. The Strategic Plan does not specify objectives specific to oil and gas leasing but provides general direction to considering opportunities for energy development and the supporting infrastructure on National Forest System lands.

The Energy Policy Act of 2005

The Energy Policy Act or 2005 directs the Secretaries of the Interior and Agriculture to improve coordination and consultation on oil and gas leasing activities, including inspection and enforcement. The Secretaries of Agriculture and Interior entered into a MOU in April 2006 (FS Agreement No. 06-SU-11132428-052). The purpose of the MOU was to satisfy requirements of the Energy Policy Act of 2005 and to establish joint BLM and Forest Service policies and procedures for managing oil and gas leasing and subsequent actions.

Onshore Oil and Gas Order Number 1

In March 2007, Onshore Oil and Gas Order Number 1, Approval of Operations, was revised (72 FR 10308) and issued as a joint rule by the Forest Service and BLM. The order provides the requirements necessary for the approval of oil and gas operations, including reclamation, on federal onshore oil and gas leases. The revised order provides requirements for processing and administering Applications for Permit to Drill which has two parts, a Drilling Plan and a Surface Use Plan of Operations. The revised rule also addresses using Master Development Plans, encourages the voluntary use of BMPs as part of Applications for Permit to Drill processing, and requires additional bonding on certain off-lease facilities.

Executive Order 13212 – Actions to Expedite Energy-Related Projects (May 18, 2001)

Executive Order 13212 states "executive departments and agencies (agencies) shall take appropriate actions, to the extent consistent with applicable law, to expedite projects that will increase the production, transmission, or conservation of energy." Executive Order 13212 requires that: "For energy-related projects, agencies shall expedite their review of permits or take other actions as necessary to accelerate the completion of such projects, while maintaining safety, public health, and environmental protections."

Executive Order 13605 - Supporting Safe and Responsible Development of Unconventional Domestic Natural Gas Resources (April 13, 2012)

Executive Order 13605 creates an Interagency Working Group to support safe and responsible development of unconventional domestic natural gas resources. The Interagency Working Group includes the Department of Interior, Department of Agriculture, Department of Defense, and other Departments. The Executive Order states: "While natural gas production is carried out by private firms, and States are the primary regulators of onshore oil and gas activities, the Federal Government has an important role to play by regulating oil and gas activities on public and Indian trust lands, encouraging greater use of natural gas in transportation, supporting research and development aimed at improving the safety of natural gas development and transportation activities, and setting sensible, cost-effective public health and environmental standards to implement Federal law and augment State safeguards."

President's Blueprint for a Secure Energy Future (March 30, 2011)

The Blueprint for a Secure Energy Future (White House, 2011) provides a three-part strategy, one part of which includes: *Develop and Secure America's Energy Supplies: Expand Safe and Responsible Domestic Oil and Natural Gas Development and Production*. The Blueprint's actions include, "Identifying the Best Public Land Sites for Development: Domestic oil and gas development, both onshore and offshore, should take place in the right places to minimize harm to the environment as well as to public health and safety. Onshore, the Administration has implemented important reforms that require adequate planning and analysis to identify potential areas where development is most appropriate. These reforms have taken place while millions of acres of public land are offered for exploration and production."

The Blueprint's actions also include, "Encouraging Responsible Development Practices for Natural Gas: Recent technology and operational improvements in extracting natural gas resources, particularly shale

gas, have increased gas drilling activities nationally and led to significantly higher natural gas production estimates for decades to come. In order to take full advantage of this important domestic energy resource, we must proactively address concerns that have been raised regarding potential negative impacts associated with hydraulic fracturing ("fracking") practices. That is why the Administration is taking steps to address these concerns and ensure that natural gas production proceeds in a safe and responsible manner."

FEDERAL LEASING PROCESS

The Record of Decision that accompanies this EIS decides which areas are available and which areas are unavailable for future leasing. The BLM has the authority to issue oil and gas leases in areas identified as administratively available. If a company acquires a lease, no ground disturbance can occur on the Forest unless the company applies for an Application for Permit to Drill (APD) and the APD is approved by the federal government. An environmental analysis including public involvement would be conducted by the Forest Service in cooperation with the BLM in regard to proposed roads, wells and other ground disturbance in the APD. After the environmental analysis and public involvement, the Forest Service would decide whether to approve the surface use plan of operations of the APD, and if so, with what Conditions of Approval. The BLM would decide whether to issue the APD, and if so, with what Conditions of Approval. The general steps in the oil and gas leasing and subsequent oil and gas operations process are:

(1) Forest Service and BLM leasing availability environmental analysis (Chapter 3, Section D of this FEIS)

(2) Forest Service notification to BLM of lands administratively available for leasing

(3) BLM offers lease

(4) BLM issues lease

(5) No surface disturbing activities occurs or is allowed unless and until Application for Permit to Drill APD is submitted to and authorized by BLM, including FS approval of Surface Use Plan of Operations (SUPO)

(6) If APD is submitted to BLM, then BLM and Forest Service conduct environmental analysis of proposed operations. Forest Service makes decision on approval of SUPO; BLM makes decision on approval of APD, including the Drilling Plan and SUPO.

(7) APD administered, inspected and enforced by BLM. SUPO, including interim reclamation, administered, inspected, and compliance enforced by Forest Service.

(8) BLM and Forest Service ensure final reclamation

LEASING OPTIONS

Legally Unavailable

These are lands legally unavailable, such as withdrawn from leasing by congressional designation in Wilderness or National Scenic Area legislation.

Administratively Unavailable

Forest Service determines administratively that the lands with federal rights will not be made available for leasing. Existing leases would remain in effect.

Standard Lease Terms

Standard lease terms restrict and control the lessee's use and occupancy of leased lands by subjecting the lease right to: 1) reasonable measures as may be required by the authorized officer to minimize adverse impacts to other resource values, land uses or users not addressed in the lease stipulations at the time operations are proposed, 2) restrictions deriving from specific, nondiscretionary statutes; and 3) any stipulations attached to the lease. Standard lease terms, Section 6, require, "Lessee must conduct operations in a manner that minimizes adverse impacts to land, air, and water, to cultural, biological, visual, and other resources, and to other land uses or users. Lessee must take reasonable measures deemed necessary by lessor to accomplish the intent of this section. To the extent consistent with lease rights granted, such measures may include, but are not limited to, modification to siting and design of facilities, timing of operations, and specification of interim and final reclamation measures." BLM regulation 43 CFR 3101.1-2 states: "At a minimum, measures shall be deemed consistent with lease rights granted provided that they do not: require relocation of proposed operations by more than 200 meters; require that operations be sited off the leasehold; or prohibit new surface disturbing operations for a period in excess of 60 days in any lease year."

Standard lease term operations cannot violate any other federal environmental protection laws (e.g., Clean Air Act, Clean Water Act, Endangered Species Act, etc.). Compliance with federal laws, such as the Endangered Species Act, could require use or occupancy prohibitions beyond the 200 meters or 60 day time period.

Stipulations

Stipulations are severe constraints on a lease that exceed the acreage or degree of constraints that might be expected under standard lease terms. Generally, stipulations affect contiguous areas larger than 40 acres. Some stipulations, depending on the acreage and degree of constraint, may make lease operations extremely costly and difficult, or technically or economically unfeasible.

No Surface Occupancy (NSO)

Use or occupancy of the land surface for oil and gas exploration or development is prohibited to protect identified resource values under the NSO stipulation. NSO is intended for use only when standard lease terms or other stipulations are determined insufficient to adequately protect the public interest. NSO applies to all uses and facilities associated with oil and gas development including well sites, drilling and pad construction, central tank batteries, access roads, pipelines, or other related facilities.

Timing Limitation (TL)

The TL stipulation (often called seasonal restrictions) prohibits surface use during specified time periods to protect identified resource values. A TL applies for restrictions longer than 60 days and shorter than one year. This stipulation does not apply to the operation and maintenance of production facilities unless the findings of analysis demonstrate the continued need for such mitigation and that less stringent, project-specific mitigation measures would be insufficient. Examples of a TL stipulation include, but are not limited to, limitations developed to protect wildlife during critical time periods.

Controlled Surface Use (CSU)

The CSU stipulation is intended to be used when occupancy and use are generally allowed on all or portions of the lease area year-round, but where restrictions or controls are necessary for specific types of activities rather than all activity. The CSU stipulation is used to identify constraints on surface use or operations that may otherwise exceed the mitigation provided by Section 6 of the standard lease terms and the regulations and operating orders. The stipulation should explicitly describe the activity that is to be restricted or controlled or the operation constraints required, and must identify the applicable area and the reason for the requirement.

AFFECTED ENVIRONMENT

POTENTIAL OIL AND GAS ACTIVITY ON THE GEORGE WASHINGTON NATIONAL FOREST

Oil & Gas Resources on the Forest

Oil and gas resources on the Forest are discussed in the Reasonable Foreseeable Development Scenario (RFD) prepared by BLM (Appendix K). The Marcellus Shale which occurs on more than half the Forest is the oil and gas resource of primary interest where exploration and development are reasonably foreseeable. The Utica Shale may occur at depth beneath the Forest, but its presence, continuity, geologic characteristics, and suitability as an oil and gas resource on the Forest are unknown. Exploration for the Marcellus Shale may include some exploration for the Utica Shale which, if present, would be at greater depth than the Marcellus Shale. But the development of shale gas, if it occurs on the Forest, is expected to be in Marcellus Shale. In any case, the number and type of oil and gas wells (a mix of horizontal and vertical wells), the miles of roads and pipelines, the amount of water for hydraulic fracturing, and other assumptions used for each alternative are reasonable assumptions to use to assess impacts of the alternatives.

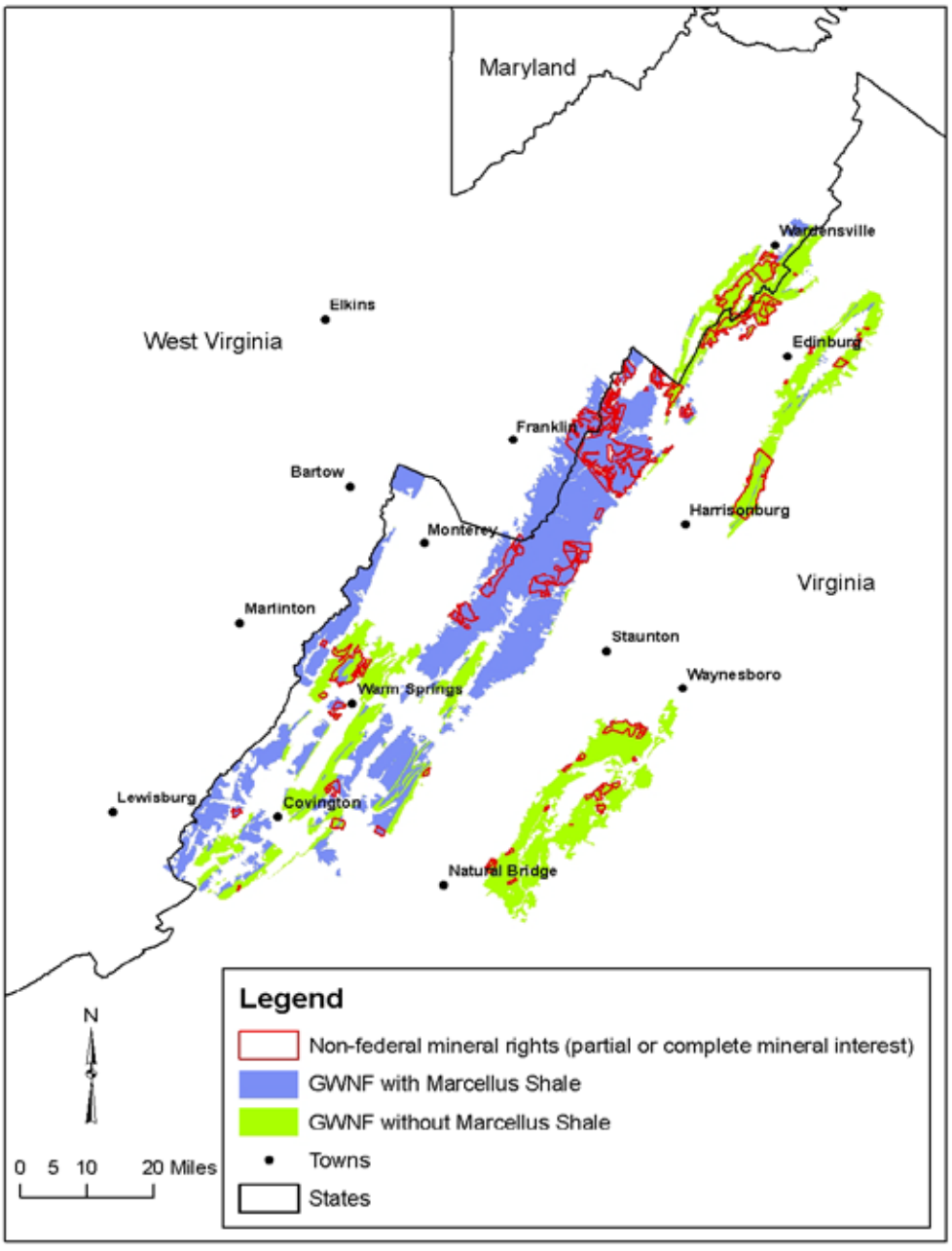

Figure 3D-1. Non-federal mineral rights on GWNF. Interpreted surface and subsurface extent of the Marcellus Shale on GWNF in Virginia and West Virginia using U.S. Geological Survey geologic map data (Dicken et al. 2005; Nicholson et al. 2005)

Marcellus Shale

The Marcellus Shale in Virginia and West Virginia is shown in Figure 3D-2 Marcellus Shale in Virginia and West Virginia, location map. The Marcellus Shale on GWNF is shown in Figure 3D-3 Marcellus Shale on GWNF in Virginia and West Virginia. The mineral status of the GWNF and relationship to Marcellus Shale is shown in GWNF Mineral Status and Marcellus Shale Table 3D-1. In a 2011 assessment of the undiscovered gas resources of the Devonian Marcellus shale, the USGS identified three Marcellus shale assessment units (Coleman et al. 2011). Lands on the GWNF lie within the Folded Marcellus Assessment Unit. It is estimated that this assessment unit contains less than 1 percent of the total undiscovered gas resources in the three assessment units.

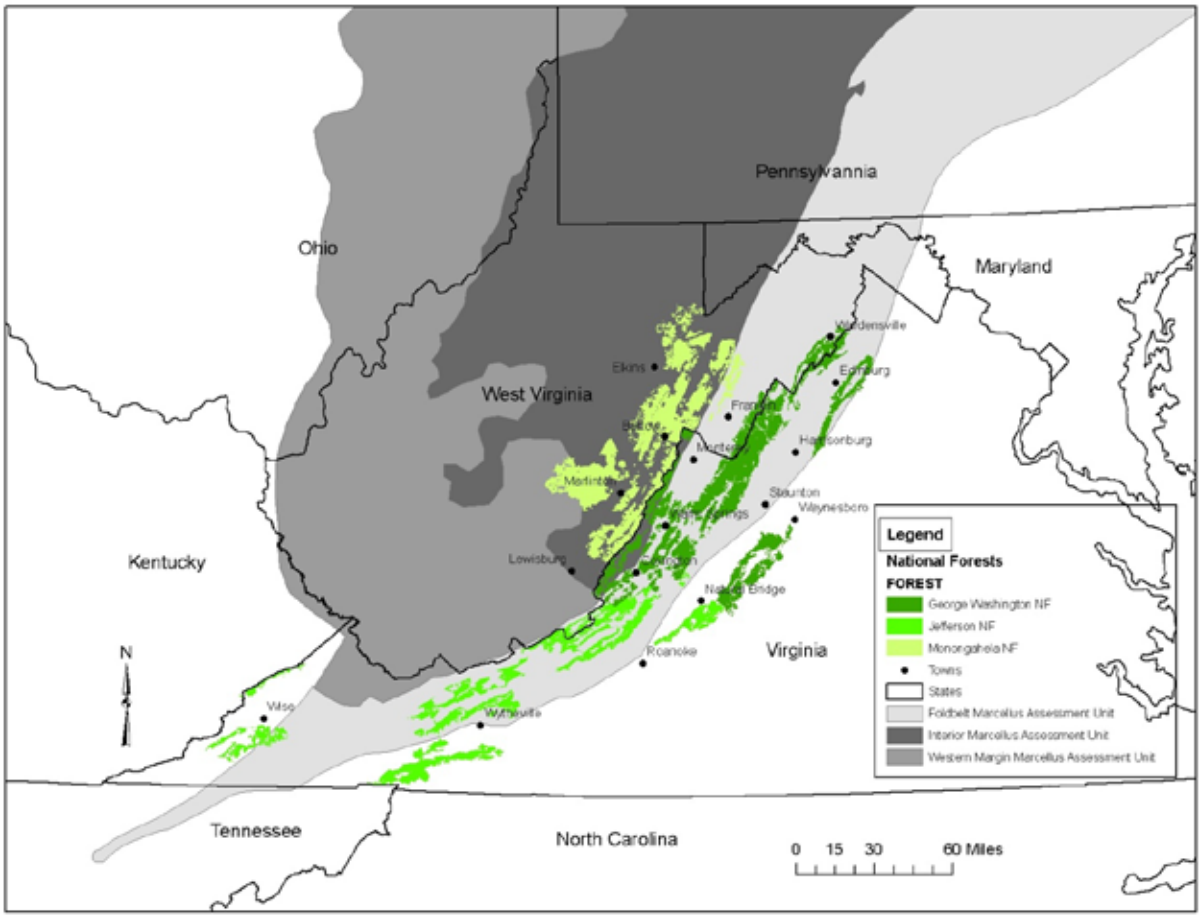

Figure 3D-2. Regional setting showing location of the George Washington NF in relation to U.S. Geological Survey Marcellus Shale Assessment Units (AU). Marcellus Shale is located within the AUs but Marcellus Shale is not present everywhere in the AU study areas, and when present may or may not be commercial for natural gas production. Most of George Washington NF is located in the Folded Marcellus AU where the Marcellus Shale is present in the subsurface on roughly half the landscape, but is not present in the subsurface on the other half of the landscape (Figure 3D-3). Modified after: U.S. Geological Survey Fact Sheet 2011–3092 (Coleman et al. 2011)

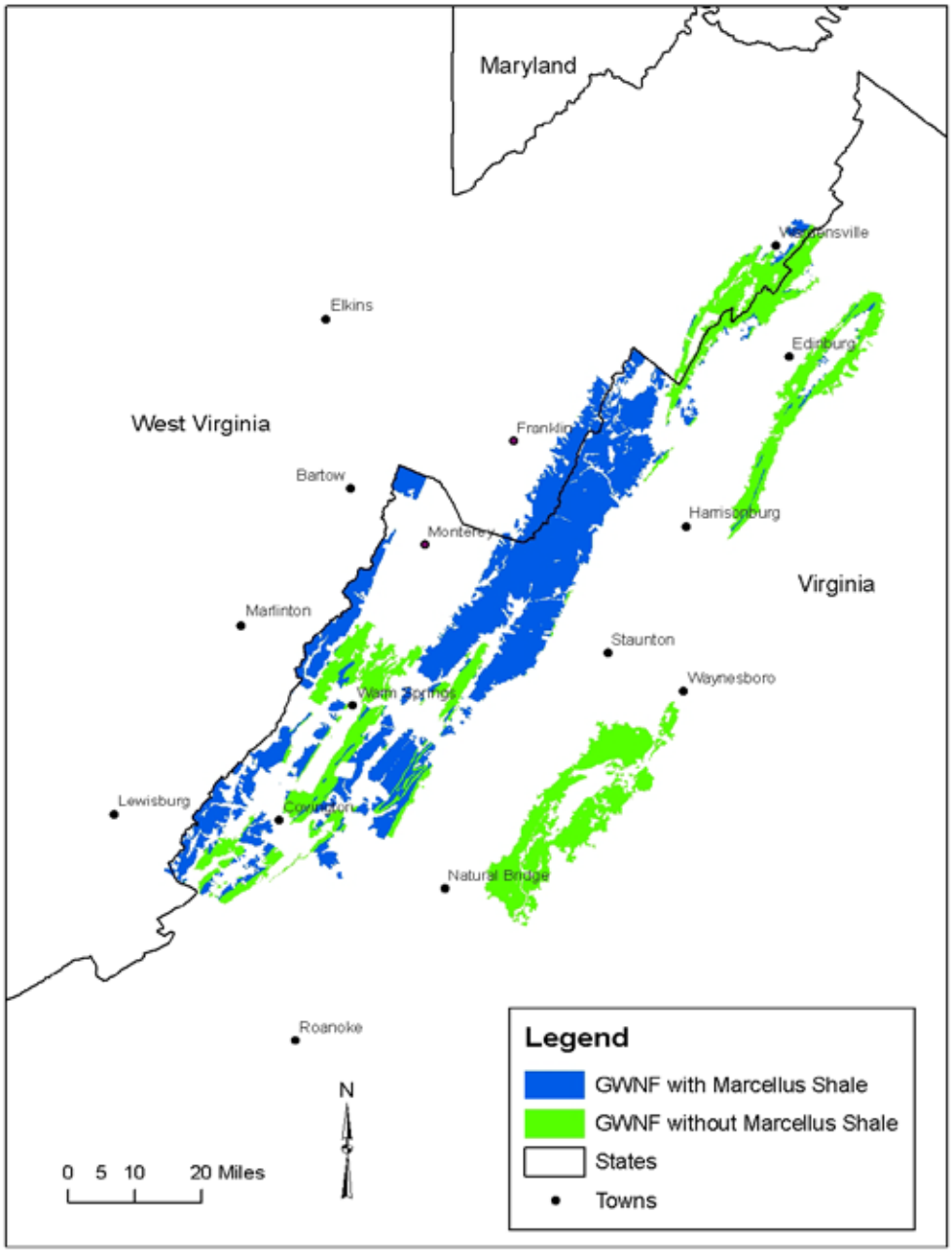

Figure 3D-3. Interpreted surface and subsurface extent of the Marcellus Shale on GWNF in Virginia and West Virginia using U.S. Geological Survey geologic map data (Dicken et al. 2005; Nicholson et al. 2005).

Table 3D-1. GWNF Mineral Status and Marcellus Shale

Mineral Status	Acres	Percent of GWNF (%)	Marcellus Shale Acres	Percent of Land Status in Marcellus Shale (%)
Total GWNF Acres	1,065,499	100.0%	592,300	55.6%
Withdrawn from mineral leasing by law	50,727	4.8%	22,537	44.4%
Not withdrawn from mineral leasing by law	1,014,772	95.2%	569,763	56.1%
Outstanding or reserved mineral rights - Partial or complete private mineral interest (subtotal of "not withdrawn" acres)	167,206	15.7%	97,615	58.4%
100% federal mineral ownership (subtotal of "not withdrawn" acres)	847,566	79.5%	472,148	55.7%
Existing federal oil & gas leases	10,243	1.0%	10,243	100.0%

Private Mineral Rights on NFS lands

The federal government owns 100% mineral rights on about 84% of the Forest. Private parties own mineral rights on about 16% of the Forest (Figure 3D-1 Non-federal mineral rights on GWNF). These outstanding or reserved mineral rights are partial or complete mineral interests. Private mineral rights are constitutionally protected property rights. Decisions on federal oil and gas leasing apply to federally-owned mineral rights, and do not apply to privately-owned mineral rights (outstanding or reserved mineral rights) on NFS lands. Oil and gas exploration and development on private mineral rights on NFS lands can occur regardless of which alternative is chosen. Assuming 16% of the GWNF Baseline Reasonably Foreseeable Development (RFD) is due to exercise of private mineral rights on the Forest, the projected oil and gas activity for private mineral rights is 16% of the GWNF Baseline RFD (Table 3D-2).

If the federal government were to acquire any private mineral rights that include oil and gas rights, then these newly-acquired federal mineral rights would be administratively available or unavailable based on the Management Prescription of the area.

Existing Federal Oil and Gas Leases

As of May 2013, federal oil and gas leases were in effect on about 1% of the Forest (10,243 acres). Oil and gas exploration and development on existing federal oil and gas leases can occur regardless of which alternative is chosen. Assuming 1% of the GWNF Baseline RFD is due to existing federal oil and gas leases, the projected oil and gas activity for existing federal oil and gas leases is 1% of the GWNF Baseline RFD (Table 3D-2). Existing federal oil and gas leases would be managed under the existing leases terms and conditions until the leases expire, terminate or are relinquished, at which time the lands would be administratively available or unavailable based on the Management Prescription of the area.

ALTERNATIVES CONSIDERED IN DETAIL

The alternatives considered for the Forest Plan decisions that are evaluated in other sections of Chapter 3 also responded to the oil and gas issue by varying the amounts and land allocations of acres that are available or unavailable for federal leasing, as well as the leasing options. Congressionally withdrawn areas, such as Wilderness and Mount Pleasant National Scenic Area (NSA), are legally unavailable for leasing for all alternatives. For the remaining areas, the suitable use associated with oil and gas leasing included whether lands would be administratively available or unavailable for federal oil and gas leasing, and if available, under what terms and conditions. The lease options are: 1) administratively unavailable; 2) available with standard lease terms and conditions; 3) available with Controlled Surface Use (CSU) or Timing Stipulation; and 4) available with No Surface Occupancy Stipulation (NSO).

Existing Conditions Common in All Alternatives

1. Congressionally withdrawn areas, such as Wilderness and Mount Pleasant National Scenic Area (NSA), are legally unavailable for federal oil and gas leasing.

2. Existing federal oil and gas leases are valid existing rights in place before the Revised Forest Plan is approved. Existing leases would be managed under the existing leases terms and conditions until the leases expire, terminate or are relinquished, at which time the lands would be administratively available or unavailable based on the Management Prescription of the area. An exception is Alterntive I where the decision is made that these lands are available for leasing.

3. The federal government owns 100% mineral rights on about 84% of the Forest. Private parties own mineral rights on about 16% of the Forest. These outstanding or reserved mineral rights are partial or complete mineral interests. Private mineral rights are constitutionally protected property rights. In each alternative, decisions on federal oil and gas leasing apply to federally-owned mineral rights, and do not apply to privately-owned mineral rights (outstanding or reserved mineral rights) on NFS lands. Oil and gas exploration and development on private minerals on NFS lands can occur regardless of which alternative is chosen. If the federal government were to acquire private mineral rights that include oil and gas rights, then these newly-acquired federal mineral rights would be administratively available or unavailable based on the Management Prescription of the area.

4. Assuming 16% of the GWNF Baseline RFD is due to private mineral rights and 1% is due to existing federal oil and gas leases, the projected oil and gas activity common for all alternatives is 17% of the GWNF Baseline RFD (Table 3D-2). The oil and gas activity comprising this 17% portion of the GWNF Baseline RFD is shown as Alternatives C and I in Table 3D-3.

Environmental Protections Common to Federal Oil and Gas Leasing in all Alternatives

Federal oil and gas leasing is subject to a wide range of federal and state laws and regulations to apply and enforce environmental protections on oil and gas exploration and development. The Department of Interior and the Department of Agriculture each has roles and regulations in administering the leasing laws Congress established for the federal oil and gas leasing program on National Forests System lands. The BLM and Forest Service each have regulations providing for environmental protections in leasing and on-the-ground operations under a lease.

1. Federal oil and gas leases have environmental protection requirements, such as in Section 6 of the standards lease terms:

> "Conduct of operations - Lessee shall conduct operations in a manner that minimizes adverse impacts to the land, air, and water, to cultural, biological, visual, and other resources, and to accomplish the intent of this section. To the extent consistent with lease rights granted, such measures may include, but are not limited to, modification to siting or design of facilities, timing of operations, and specification of interim and final reclamation measures."

2. Proposed lease operations are subject to a wide range of laws and regulations, including Endangered Species Act, Archaeological Resources Protection Act, Federal Water Pollution Control Act, Clean Water Act, Clean Air Act, National Environmental Policy Act, and all the other environmental protection laws and regulations applicable to National Forest System lands. Under a federal law such as the Endangered Species Act, the Forest Service at the Application Permit to Drill (APD) stage can control or prohibit surface occupancy of any size acreage, when justified, without a lease stipulation.

3. Two levels of environmental protections are incorporated from the National Environmental Policy Act as applied to federal oil and gas leasing. In addition to the environmental analysis under NEPA and the environmental protections developed here for determining leasing availability, a second environmental analysis under NEPA and environmental protections would be required for proposed actual operations under a lease. The Forest Service would be the lead agency and BLM a cooperating agency for NEPA for the federal decision on proposed operations on NFS lands.

After a federal oil and gas lease is issued, the leaseholder cannot construct a road, drill a well, or conduct ground disturbing operations until the federal government (BLM and Forest Service) reviews and approves plans for each proposed well, road, and associated facilities. Before ground disturbing operations can occur, the leaseholder must submit for review and approval an Application for Permit to Drill (APD) that includes a Drilling Plan and a Surface Use Plan of Operations.

4. BLM regulations for federal oil and gas lease operations have environmental protections requirements, including Onshore Oil and Gas Orders. BLM regulation Onshore Oil and Gas Order No. 1, contain environmental protection requirements for the Drilling Plan and Surface Use Plan of Operations in the APD. For example, the Drilling Plan includes ground water protection requirements such as Section IIID3:

> "The Drilling Plans must be in sufficient detail to permit a complete appraisal of the technical adequacy of, and environmental effects associated with, the proposed project. The Drilling Plan must adhere to the provisions and standards of Onshore Oil and Gas Order Number 2 (see 53 FR 46790) (Order 2) and, if applicable, Onshore Oil and Gas Order Number 6 (see 55 FR 48958) (Order 6), and must include the following information:
>
> a. Names and estimated tops of all geologic groups, formations, members, or zones.
> b. Estimated depth and thickness of formations, members, or zones potentially containing usable water, oil, gas, or prospectively valuable deposits of other minerals that the operator expects to encounter, and the operator's plans for protecting such resources.
> c. The operator's minimum specifications for blowout prevention equipment and diverter systems to be used, including size, pressure rating, configuration, and the testing procedure and frequency. Blowout prevention equipment must meet the minimum standards outlined in Order 2.
> d. The operator's proposed casing program, including size, grade, weight, type of thread and coupling, the setting depth of each string, and its condition. The operator must include the minimum design criteria, including casing loading assumptions and corresponding safety factors for burst, collapse, and tensions (body yield and joint strength). The operator must also include the lengths and setting depth of each casing when a tapered casing string is proposed. The hole size for each well bore

section of hole drilled must be included. Special casing designs such as the use of coiled tubing or expandable casing may necessitate additional information.

e. The estimated amount and type(s) of cement expected to be used in the setting of each casing string. If stage cementing will be used, provide the setting depth of the stage tool(s) and amount and type of cement, including additives, to be used for each stage. Provide the yield of each cement slurry and the expected top of cement, with excess, for each cemented string or stage.

f. Type and characteristics of the proposed circulating medium or mediums proposed for the drilling of each well bore section, the quantities and types of mud and weighting material to be maintained, and the monitoring equipment to be used on the circulating system."

The Surface Use Plan of Operations in the APD includes such requirements as:
"Section IIID4g: Methods for Handling Waste: The Surface Use Plan of Operations must contain a written description of the methods and locations proposed for safe containment and disposal of each type of waste material (e.g., cuttings, garbage, salts, chemicals, sewage, etc.) that results from drilling the proposed well. The narrative must include plans for the eventual disposal of drilling fluids and any produced oil or water recovered during testing operations. The operator must describe plans for the construction and lining, if necessary, of the reserve pit."

"Section IIID4j: Plans for Surface Reclamation: The operator must submit a plan for the surface reclamation or stabilization of all disturbed areas. This plan must address interim (during production) reclamation for the area of the well pad not needed for production, as well as final abandonment of the well location."

5. BLM regulation Onshore Oil and Gas Order No. 1 also contains General Operation Requirements with environmental protections for cultural and historic resources, Endangered Species Act, safety, and surface protection, such as Section IVc:

"Surface Protection. Except as otherwise provided in an approved Surface Use Plan of Operations, the operator must not conduct operations in areas subject to mass soil movement, riparian areas, floodplains, lakeshores, and/or wetlands. The operator also must take measures to minimize or prevent erosion and sediment production. Such measures may include, but are not limited to:

- Avoiding steep slopes and excessive land clearing when siting structures, facilities, and other improvements; and
- Temporarily suspending operations when frozen ground, thawing, or other weather-related conditions would cause otherwise avoidable or excessive impacts."

6. Onshore Oil and Gas Order No. 2 contains environmental protection requirements for Drilling Operations, such as: Section IIIB:

"The proposed casing and cementing programs shall be conducted as approved to protect and/or isolate all usable water zones, lost circulation zones, abnormally pressured zones, and any prospectively valuable deposits of minerals."

7. Standard lease terms and federal regulations allow the Forest Service and BLM to 1) control surface use of proposed activities in the lease area, and 2) prohibit surface occupancy on some areas within the lease area. For example, a proposed oil and gas facility, such as a road, can be relocated up to 200 meters without any stipulation.

8. Proposed lease operations are subject to environmental protection requirements in 1) Forest Service regulations, including the 36 CFR 228E regulations developed to implement Federal Onshore Oil and Gas Leasing Reform Act of 1987, and 2) the Forest Plan. For example, the Forest Service oil and gas

regulation surface use requirements (36 CFR 228.108) require environmental protections relating to access facilities, cultural resources, fire prevention, fisheries, wildlife, plant habitat, threatened and endangered species, safety, wastes including drilling wastes, watershed protection including surface water and groundwater, erosion and sediment production, riparian areas and wetlands, and reclamation. Soil losses would be reduced or minimized through the application of Best Management Practices on a site-specific basis. Examples of such practices include use of erosion curtains to protect drainages, surfacing roads, water bars and check dams to control runoff, stockpiling of topsoil for reclamation and revegetation, and use of rip-rap to control gullying and head-cutting. Other measures include appropriate engineering design of roads, well pads, and ancillary facilities; and avoidance of steep and/or unstable slopes and sensitive soils. The Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development (commonly referred to as the Gold Book) provides operators with a combination of guidance and standards for ensuring compliance with agency policies and operating requirements, such as those found in the Code of Federal Regulations at 43 CFR 3000 and 36 CFR 228 Subpart E; Onshore Oil and Gas Orders (Onshore Orders); and Notices to Lessees (NTLs) and for use of Best Management Practices (U.S. Department of the Interior and U.S. Department of Agriculture 2007).

9. The Stipulation for National Forest System lands would be part of all leases on NFS lands and requires the lessee to comply with the Secretary of Agriculture's rules and regulations for use and occupancy of National Forest System lands prior to approval of a permit/operation plan by the Secretary of Interior.

10. Proposed lease operations are subject to the State laws and regulations governing oil and gas operations, including requirements for environmental protection and reclamation. The Virginia Department of Mines, Minerals and Energy, Division of Oil and Gas administers Virginia's Gas and Oil Act of 1990 and the regulation authorized by the act that "provides a comprehensive program to protect public safety and the environment from potential impacts associated with gas and oil exploration and development. The law and regulation govern activities from prior to the initial disturbance of land for site preparation until after a well is plugged and reclaimed. The installation and operation of gathering pipelines are also governed by the law and regulation. The Department of Mines, Minerals and Energy's (DMME) Division of Gas and Oil (DGO) is responsible for administering the law and regulation. The law and regulation require an operating permit and place special emphasis on water quality protection, erosion and sediment control, and protection of the public from safety hazards. The requirements are designed to prevent offsite disturbances from gas and oil operations." (Virginia Department of Mines, Minerals and Energy, Division of Gas and Oil 2012a).

11. Virginia Gas Well Permit Requirements include: "Permits are required for ground-disturbing geophysical exploration, exploration wells, development wells and gathering pipelines.

- Applicants for permits are required to notify parties who may be directly affected by the proposed operation, including surface owners, coal owners and mineral owners.
- These parties have the right to object to permits on specific grounds that are outlined in the law.
- Applicants also must inform local governments, and publish notices of their applications in at least one newspaper of general circulation which is published in the county, city or town where the well is proposed to be located.
- Applications must contain a description of all aspects of any operation.

"Operation plans must include a description of the following:

- The pre-development condition of the site
- The construction to be undertaken on the site including information on acreage to be disturbed, blasting activities, proposed new roads, and existing access roads
- The erosion and sediment control plan
- All well site equipment and facilities
- The design and operation of any pits

- The drilling and stimulating plan, including information on the water and constituents of the drilling fluids
- Management and disposal of pit fluids, produced waters, drill cuttings and solids

"The Virginia Division of Gas and Oil (DGO) reviews all applications and may deny a permit or require the applicant to submit more information or amend the proposed operation plan to ensure that the operator will comply with the law and regulation. Applicants must post a bond to guarantee that money is available for site reclamation and plugging should the operator fail to perform the work. The operator may not begin site work until DGO issues a permit." (Virginia Department of Mines, Minerals and Energy, Division of Gas and Oil, 2012b)

Virginia Division of Gas and Oil program for Inspection and Enforcement includes:

> "In order to insure compliance with the Virginia Gas and Oil Act and Regulation, field staff from the Division of Gas and Oil make routine inspections of well sites, gathering pipelines, facilities and other permitted sites and activities. Frequency of inspection is determined by a priority system which categorizes each permitted site or operation according to its level of activity or the stability of the associated disturbed area. Highest priority for inspection is given to sites that are under construction or being drilled or completed, while lowest priority is given to older permits with stabilized sites.
>
> "If inspections reveal a lack of regulatory compliance, actions that may be taken range from obtaining voluntary compliance through requests or warnings to revocation of permits. If voluntary compliance cannot be achieved, the problem involves off-site disturbance, or, at the discretion of the inspector, the infraction is sufficiently severe, a Notice of Violation may be issued to the permittee. The Notice of Violation may be accompanied by recommendations for Civil Charges.
>
> "If conditions causing the issuance of a Notice of Violation are not abated, or if a condition or practice on a permitted site creates an imminent danger to the health and safety of the public, a Closure Order may be issued which causes cessation of operations until the conditions are corrected. If compliance cannot be achieved by any of the means described above, permits can be suspended or revoked and bonds may be forfeited for the purpose of plugging wells or reclaiming sites." Virginia Department of Mines, Minerals and Energy, Division of Gas and Oil. 2012c

On October 17, 2011 the Commonwealth of Virginia provided more information about Virginia Department of Mines, Minerals and Energy (DMME) gas and oil regulations:

> "DMME gas and oil regulations would apply to any wells drilled within GWNF. These regulations require submission and approval of a stimulation plan. This plan must address the specifics of how the well will be stimulated, including fluids to be used, additives, and other factors. DMME gas and oil permitting requires the operator to complete site-specific assessments of the surface and underground conditions to be affected by drilling, to ensure that operation will not cause off-site disturbances or pollution to surface or groundwater."
>
> "To date, there have been no known instances of surface water or groundwater degradation from hydraulic fracturing in Virginia. This is largely due to casing and fluid management requirements that must be met when drilling and stimulating a well. There are multiple layers of steel pipe and concrete extending through groundwater zones that provide protection and prevent the intrusion of water into a gas flow stream. Cement casing is required at least 300 feet below the surface or 50 feet beneath the deepest known groundwater horizon, whichever is deeper. Typically, hydraulic fracturing is conducted in formations that are at least 500 feet, and often thousands of

> feet (for shale) below fresh water zones. These requirements ensure protection of groundwater from well stimulation fluids."
>
> "DMME regulations also protect water quality once the fluids return to the surface…No off-site disturbances or discharges are allowed. Fluids are normally disposed of in an off-site permitted facility such as a Class II EPA injection well. Well operators are also increasingly reusing or recycling stimulation fluids in order to minimize disposal. DMME gas and oil regulations also govern on-site road and gathering pipeline construction and operation. Construction must meet all erosion and sediment control, storm water, and reclamation requirements, and are covered under performance bonds." (Virginia Department of Environmental Quality 2011)

12. The State of West Virginia also has law, regulation, and permit requirements for oil and gas operations. West Virginia Code of State Rules Title 35 includes Oil and Gas Wells and Other Wells requirements (West Virginia Secretary of State 2012a) such as:

- Prevention of surface and underground water pollution
- Operational Regulations on Liquid Injection and Waste Disposal Wells
- Fresh Water Casing
- Water Supply Testing and Notice to Surface Owners
- Construction and maintenance of drilling sites to prevent spills and excess sedimentation.
- Construction and maintenance of wastewater pits and freshwater impoundments
- Requirements for Pipelines
- Inspection and Enforcement
- Groundwater Remediation
- Bonds
- Plugging, Abandonment and Reclamation

In August 2011 West Virginia issued Rules Governing Horizontal Well Development (West Virginia Secretary of State 2012b) that includes requirements such as:

- Operational rules to protect quality and quantity of water in surface and ground water systems.
- Casing and cement standards to keep fluids or natural gas from entering ground or surface waters.
- Water Management Plan
- A listing of anticipated additives that may be used in the water used for fracturing or stimulating the well, and upon completion, a listing of the additives that were actually used.
- Identification of the current designated and existing water uses, including any public water intakes within one mile downstream of the withdrawal location.
- A demonstration, using methods acceptable to the Secretary, that sufficient in-stream flow will be available downstream of the point of withdrawal.
- Identification of the methods to be used to prevent significant adverse impact to aquatic life.
- Well Site Safety Plan
- Material Safety Data Sheets (MSDS) for all materials and chemicals on the well site shall be readily available and maintained at the well site.

In December 2011 West Virginia passed the Horizontal Well Development Act (Natural Gas Horizontal Well Control Act) (West Virginia Legislature 2011) that includes requirements such as:

- Protection of quality and quantity of water in surface and ground water systems both during and after drilling operations and during reclamation.
- Well location distance restrictions in relation to water wells, residences, perennial streams, naturally producing trout streams, and public surface or groundwater intakes.
- Water Management Plan
- A listing of anticipated additives that may be used in the water used for fracturing or stimulating the well, and upon completion, a listing of the additives that were actually used.

- Identification of the current designated and existing water uses, including any public water intakes within one mile downstream of the withdrawal location.
- A demonstration, using methods acceptable to the Secretary, that sufficient in-stream flow will be available immediately downstream of the point of withdrawal.
- Methods to be used for surface water withdrawals to minimize adverse impact to aquatic life.
- The planned management and disposition of wastewater after completion from fracturing, refracturing, stimulation and production activities;
- Casing and cement standards. Casing, sealing or otherwise managing wells to keep returned fluids from entering ground and surface waters.
- Erosion and sediment control plan
- Protection for karst terrain including caves and sinkholes.

Reasonable Foreseeable Development Scenario (RFD)

Projections of the kind and amount of oil and gas activity that could be reasonably anticipated were made in order to analyze the environmental effects that could occur as a result of federal oil and gas leasing under each alternative. Forest Service regulations (36 CFR 228.102 (c) (3 and 4)) require the analysis to "project the type/amount of post-leasing activity that is reasonably foreseeable as a consequence of conducting a leasing program consistent with that described for each alternative" and "analyze the reasonable foreseeable impacts of post-leasing activity under (c)(3) of this section as a part of the analysis." This post-leasing activity is the oil and gas activity, including construction of roads, well pads, pipelines, and associated facilities that would be expected under each alternative.

Projecting the post-leasing activity is a multi-step process that begins with a Reasonable Foreseeable Development Scenario (RFD) prepared by the Bureau of Land Management (BLM) (Appendix K). The RFD provides a baseline projection of post-leasing activity from which projections for each alternative are developed. To provide the baseline projection the BLM prepared a Reasonable Foreseeable Development Scenario based on the assumption that all the Forest except areas withdrawn from leasing by law (Wilderness and National Scenic Area) would be available for oil and gas leasing under standard lease terms and conditions (Appendix K-BLM RFD). The BLM baseline RFD estimates post-lease activity of 319 natural gas wells and associated surface disturbance including wells pads, roads, and pipelines over a 15 year planning horizon.

The BLM baseline RFD assumptions for surface disturbance are modified here by adding acres associated with pipelines and water use for drilling. The resulting RFD assumptions for surface disturbance, water use, and reclamation are:

Drilling Phase:

- Seismic Exploration (Vibroseis): 163 miles on existing roads and the use of heliportable seismic equipment in other areas (casual use minimal disturbance)
- Exploration/Evaluation Well Pad (vertical well) - (300'x300' pad): 2.07 acres per pad
- Exploratory/Evaluation Well Pad (vertical well) Access Road (40'x 1.5 mile/well): 7.27 acres per road
- Development Well Pad (vertical well) - (300'x300'): 2.07 acres per pad
- Development Well Pad (vertical well) Access Roads (40'x1.0 mile/well): 4.85 acres per road
- Development Well Pad (horizontal wells, 3 wells per pad) (500'x500' pad): 5.74 acres per pad
- Development Well Pad (horizontal wells, 3 wells per pad) Access Road (40'x2.0 miles/pad): 9.70 acres per pad
- Water use for drilling vertical well: 20,000 gallons per well.
- Water use for drilling horizontal well: 100,000 gallons per well.

Post-drilling and Production Phase:

- Initial Reclamation: Part of Exploration/Evaluation Well Pad (vertical well) reclaimed: 1.84 acres per pad
- Part of Exploration/Evaluation Well Pad (vertical well) used for production: 0.23 acres per pad
- Initial Reclamation: Part of Development Well Pad (vertical well) reclaimed: 1.84 acres per pad
- Part of Development Well Pad (vertical well) used for production: 0.23 acres per pad
- Water use for hydraulic fracturing of vertical well: 400,000 gallons per well.
- Water use for hydraulic fracturing of horizontal well: 5,000,000 gallons per well.
- Initial Reclamation: Part of Development Well Pad (horizontal wells, 3 wells per pad) reclaimed: 5.22 acres per pad
- Part of Development Well Pad (horizontal wells, 3 wells per pad) used for production: 0.52 acres per pad
- Pipelines along road (additional 20' width along 90% of road miles): 2.18 acres per mile of road. Pipelines not along roads (10% of road miles) and pipelines connecting to the area or field (additional mileage estimated at 10% of road miles) - (30' wide corridor estimated as 20% of road miles): 0.73 acres per mile of road. Pipelines along roads and pipelines outside roads corridor: total 2.91 acres per mile of road.
- Off well site production facilities: 25 acres
- Final Reclamation: road acres + well pad acres + pipeline acres+ off well site production facilities acres.

Using these assumptions, the modified RFD is shown in the 3D-2 GWNF Baseline RFD Table.

Table 3D-2. GWNF Baseline Reasonably Foreseeable Development (RFD)

Activity	GWNF federal and private mineral ownerships Baseline RFD			
	Exploration/evaluation wells (vertical)	Development wells (vertical)	Development wells (horizontal)	Total
Number of wells	20	50	249	319
Roads (miles)	30	50	166	246
Roads (acres)	145	242	805	1193
Well Pads (acres)	41	103	476	621
Road & Well Pads (acres)	187	346	1,281	1,814
Well pads initial reclamation (acres)	37	92	433	562
Well pads in production (acres)	5	12	43	59
Pipelines (miles)	33	55	183	271
Pipelines (acres)	96	160	531	787
Off Site Production Facilities (acres)	0	0	25	25
Production reclamation (acres)	237	399	1,331	1,993
Total reclamation (total disturbance) (acres)	274	491	1,764	2,555
Water use for drilling (1,000s of gallons)	400	1,000	24,900	26,300
Water use for hydraulic fracturing (1,000s of gallons)	8,000	20,000	1,245,000	1,273,000

This projection of future oil and gas activity is based on the assumption that all the Forest except areas withdrawn from leasing by law would be available for oil and gas leasing under standard lease terms and conditions. Because each alternative will have more restrictive constraints on availability of federal oil and gas leasing, each alternative will project less oil and gas activity than the GWNF baseline RFD. Before projecting the future federal oil and gas activity that varies by alternative, the following section will consider the part of the future activity (GWNF baseline RFD Table) that is common to all alternatives and does not vary by alternative.

Additional Stipulations Used in Alternatives B, D, and F

In addition to leasing availability and leasing options, two additional stipulations were developed for the alternatives in the Draft Environmental Impact Statement for several alternatives. These stipulations included the following:

Horizontal Drilling Moratorium: The surface management agency (USDA-Forest Service) would have a moratorium on processing Surface Use Plan of Operations of an Application for Permit to Drill for any horizontal well and associated hydraulic fracturing. The moratorium would end on May 1, 2015. This would allow for the consideration of additional information, such as information developed by U.S. Environmental Protection Agency, for use in processing Application for Permit to Drill for horizontal wells with multi-stage hydraulic fracturing.

Horizontal Drilling Operations Control Stipulation: In cooperation with BLM, the USDA-Forest Service would scrutinize proposed operations in regard to use and disposal of surface water and groundwater, and the type and amounts of materials used in hydraulic fracturing. Applicants for Surface Use Plan of Operations of APD shall supply a list of the quantity and chemical composition of all materials proposed for use in drilling and hydraulic fracturing, including any associated Material Safety Data Sheets. The Drilling Plans must be in sufficient detail to permit a complete appraisal of the technical adequacy of the ground water protection components of the proposed drilling. The proposed casing and cementing programs shall be designed to protect and/or isolate all usable water zones, lost circulation zones, and abnormally pressured zones. The operator shall submit the proposed casing program, including size, grade, weight, type of thread and coupling, the setting depth of each string, and its condition. The operator must include the minimum design criteria, including casing loading assumptions and corresponding safety factors for burst, collapse, and tensions (body yield and joint strength). Based on an the environmental analysis, the USDA-Forest Service will determine whether use of surface water and/or groundwater on National Forest System (NFS) lands will be authorized. Use of surface water and/or groundwater may be severely limited or prohibited. Prior to conducting hydraulic fracturing operation, the operator shall submit as-built wellbore construction information so that the APD administrators (BLM and Forest Service) can assess: adequacy of surface casing to protect fresh water and to isolate potable fresh water supplies from deeper gas-bearing zones; adequacy of cement in the annular space around the surface casing; adequacy of cement on production (and intermediate) casing to prevent upward migration of fluids during all reservoir conditions; and use of centralizers to ensure that the cement sheath surrounds the casing strings. No hydraulic fracturing operation shall commence until the APD administrators provide authorization for the operation after a review of the as-built wellbore construction information. After authorization is granted, the operator shall provide the APD administrators with at least three days' notice before commencing hydraulic fracturing operation. Flowback operations shall use above ground storage tanks rather than surface impoundments. The fluid disposal plan must demonstrate that flowback water pipelines and conveyances will be constructed of suitable materials, maintained in a leak-free condition, regularly inspected and operated using all appropriate spill control and storm water pollution prevention practices. Surface disposal of hydraulic fracturing materials on NFS lands will not be authorized. Based on an environmental analysis, the USDA-Forest Service will determine whether subsurface disposal of hydraulic fracturing materials in an EPA-approved underground injection well on NFS lands will be authorized or prohibited.

Alternative A – No Action Alternative

Alternative A represents the leasing availability decision that was made concurrently with the 1993 Forest Plan, as amended through ten amendments. Of the 1,055,000 acres available for leasing, approximately 954,000 acres would be available under standard lease terms and controlled surface use occupancy stipulations. The Plan did not address horizontal drilling and high volume hydraulic fracturing since its use was not common at that time. There is no direction in the 1993 Plan or any of the amendments for the development of the Marcellus shale formation. The 10,000 acres that are administratively unavailable include the Laurel Fork area.

Alternative B

This alternative is based on changes to the 1993 Forest Plan identified in the Analysis of the Management Situation. The analysis was based on an IDT evaluation of the 1993 Forest Plan direction, monitoring and evaluation results, new policies, best available science and an attempt to balance public issues that were identified as of March 2010 for the Notice of Intent. In Alternative B, of the 983,000 acres available for leasing, approximately 767,000 acres are available under standard lease terms or controlled surface occupancy stipulations. Horizontal drilling (Marcellus shale development) is allowed on all available acres but the Horizontal Drilling Moratorium and the Horizontal Drilling Operations Control stipulations are applied. The 22,100 acres that are administratively unavailable include the Recommended Wilderness Study areas.

Alternative C

In this alternative, the emphasis is restoration and maintenance of sustainable ecological systems predominantly through natural processes, with little human intervention beyond what it required to meet legal requirements. It also addresses the need for non-motorized recreation opportunities. No new areas would be available for federal oil and gas leasing. Existing leases would remain in effect. Private mineral rights (approximately 167,200 acres) would continue to be legally available for oil and gas leasing.

Alternative D

In this alternative, restoration and maintenance of natural ecological systems would use practices that also produce a higher level of commodities and offers amenities that enhance tourism for local communities that benefit economically from forest visitors and forest products. Of the 981,000 acres available for leasing, approximately 766,000 acres are available under standard lease terms or controlled surface occupancy stipulations. Horizontal drilling (Marcellus shale development) allowed on all available acres but the Horizontal Drilling Moratorium and the Horizontal Drilling Operations Control stipulations are applied. The 24,500 acres that are administratively unavailable include Recommended Wilderness Study areas and a Recommended National Scenic Area.

Alternative E

Alternative E would actively restore and maintain vegetative compositional and structural conditions needed to provide for a variety of terrestrial and aquatic species in certain areas of the forest. Of the 980,000 acres available for leasing, approximately 695,000 acres are available under standard lease terms or controlled surface occupancy stipulations. No acres would be available for horizontal drilling (Marcellus Shale development).

Alternative F

This alternative would restore and maintain the native ecological systems while also creating many opportunities for a variety of recreation settings. The emphasis is on recreation opportunities, scenery management, and wilderness designation, while focusing ecosystem health activities in support of wildlife based recreation. Of the 763,000 acres available for leasing, approximately 600,000 acres are available under standard lease terms or controlled surface occupancy stipulations. Horizontal drilling (Marcellus shale development) would not be allowed on approximately 31,500 acres of public water supply watersheds. The remaining 731,500 available acres would be subject to the Horizontal Drilling Moratorium and the Horizontal Drilling Operations Control stipulations. The 241,800 acres that are administratively unavailable include Recommended Wilderness Study areas and Recommended National Scenic Areas.

Alternative G

Alternative G was developed after reviewing public comments and agency concerns received and developed before the Draft EIS was released. It was identified as the Preferred Alternative in the Draft EIS. This alternative provides a variety of resource benefits, including wood, wildlife, fish, range, dispersed recreation, developed recreation, minerals, wilderness and special uses, in a manner that maintains the diversity, productivity and long-term sustainability of ecosystems. It would actively restore and maintain vegetative compositional and structural conditions needed to provide for a variety of terrestrial and aquatic species in certain areas of the forest. Of the 983,000 acres available for leasing, approximately 711,000 acres are available for leasing under standard lease terms or controlled surface occupancy stipulations. No areas would be available for horizontal drilling (Marcellus Shale development). The 22,000 acres of administratively unavailable acres include Recommended Wilderness Study Areas.

Alternative H

Alternative H was developed after reviewing public comments and new information received after release of the Draft EIS. It is based on Alternative G with changes made in response to the comments and further analysis. This alternative provides a variety of resource benefits, including wood, wildlife, fish, range, dispersed recreation, developed recreation, minerals, wilderness and special uses, in a manner that maintains the diversity, productivity and long-term sustainability of ecosystems. It would actively restore and maintain vegetative compositional and structural conditions needed to provide for a variety of terrestrial and aquatic species in certain areas of the forest.

A major change from Alternative G is the decision to base the leasing availability analysis on only those acres with a high potential for gas development, which includes the James River Ranger District and most of the North River and Warm Springs Ranger Districts. Alternative H makes no decision on the availability of lands on the Lee and Pedlar Ranger Districts, on Walker Mountain on the North River Ranger District, and on Back Creek Mountain and Warm Springs Mountain on the Warm Springs Ranger District. This is based on the Reasonably Foreseeable Development Scenario (Appendix K) which identifies the Marcellus shale as the formation with a high potential for gas. If there is a future interest in leasing these deferred areas of the GWNF, a site-specific analysis would be done to determine the availability of those specific areas.

Another major change from Alternative G is the decision to allow hydraulic fracturing with additional stipulations on certain areas of the GWNF. Of the 461,000 acres available for leasing, approximately 236,000 are available under standard lease terms, 88,000 acres under controlled surface use stipulations and 137,000 under no surface occupancy stipulations. Most leasing options apply to an entire management area prescription, but there are several exceptions. The area within Management Prescription Area 13-Mosaics of Habitat on Shenandoah Mountain south of Highway 250 and above 3,000 feet in elevation are available but with no surface occupancy stipulations to protect potential habitat for the Cow Knob salamander. Portions within Semi-Primitive Non-Motorized and Semi-Primitive Motorized settings are available with controlled surface use stipulations that will limit road construction. The 128,000 acres that are administratively unavailable for leasing include: Recommended Wilderness Study areas, Shenandoah Mountain Recommended National Scenic Area, Laurel Fork, Indiana Bat-Primary Area Conservation Areas, and public water supply watersheds.

Alternative H includes a different set of mitigation and control measures for reducing potential impacts from gas drilling. These measures are described in Appendix I.

Alternative I

Alternative I was developed after reviewing public comments and new information received after release of the Draft EIS. Alternative I is the same as Alternative H except for the oil and gas leasing availability component. With respect to the availability of lands for federal oil and gas leasing, Alternative I uses the approach for administrative availability of Alternative C where no new areas would

be available for federal oil and gas leasing, except Alternative I makes the lands with existing leases available after the current leases expire. Existing leases (approximately 10,200 acres) would remain in effect. Private mineral rights (approximately 167,200 acres) would not be affected.

The following two tables compare the differences between the alternatives with respect to the amount of available acres for leasing, the leasing options and the suitability of leasing for specific management prescriptions areas or other resource conditions on the GWNF.

Table 3D-3. Federal Oil and Gas Leasing Availability by Alternative (thousands of acres)

Category	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Administratively Available	995	983	0	981	980	763	983	461
Standard Lease Terms	139	615	0	609	535	495	550	236
Controlled Surface Use Stipulation	815	152	0	157	160	105	161	88
Timing Stipulation	0	14	0	14	14	14	14	0
No Surface Occupancy Stipulation	41	202	0	201	271	149	259	137
Administratively Unavailable	10	22	1,005	25	26	242	22	128
Legally Unavailable	51	51	51	51	51	51	51	51
Administratively Available Decision Deferred*	0	0	0	0	0	0	0	416
Available, Under Existing Lease	10	10	10	10	10	10	10	10
Total Forest Acres	1,066	1,066	1,066	1,066	1,066	1,066	1,066	1,066
Additional Control Measures on Drilling Operations	0	983	0	981	0	731	0	461
Horizontal Drilling Moratorium	0	983	0	981	0	731	0	0
No Horizontal Drilling Stipulation	0	0	0	0	980	32	983	0

*Administratively available decision deferred on Pedlar and Lee Ranger Districts and portions of the Warm Springs and North River Ranger Districts.

Table 3D-4. Oil and Gas Leasing Options by Management Prescription Area

Rx	Management Prescription Area Description	Oil and Gas Leasing Availability Alts A, B, D, E, F and G	Oil and Gas Leasing Suitability Alt H*
1A	Designated Wilderness	Legally Unavailable	Legally Unavailable
1B	Recommended Wilderness Study	Administratively Unavailable	Administratively Unavailable
2C2	Eligible Wild and Scenic River-Scenic	CSU	NSO
2C3	Eligible Wild and Scenic River-Recreation	CSU	NSO
4A	Appalachian Trail Corridor	NSO	NSO
4B1	Research Natural Areas	NSO	NSO
4C1	Geologic Areas	CSU	NSO
4D	Special Biological Areas	CSU	NSO
4D1	Key Natural Heritage Community Area	CSU	NSO
4E	Cultural/Heritage Areas	NSO	NSO
4F	Mt Pleasant National Scenic Area	Legally Unavailable	Legally Unavailable
4FA	Recommended National Scenic Areas	Administratively Unavailable	Administratively Unavailable

Rx	Management Prescription Area Description	Oil and Gas Leasing Availability Alts A, B, D, E, F and G	Oil and Gas Leasing Suitability Alt H*
5A	Administrative Sites	Standard	Standard
5B	Communication Sites	Standard	Standard
5C	Utility Corridors	Standard	Standard
7A1	Scenic Byways	CSU	CSU
7B	Scenic Corridors and Viewsheds	CSU	CSU
7C	ATV Use Areas	Standard	Standard
7D	Concentrated Recreation Areas	CSU	CSU
7E	Dispersed Recreation Areas	Standard	Standard
7E1	Dispersed Recreation Areas-Unsuitable for Timber Production	Standard	Standard
7E2	Dispersed Recreation Areas-Suitable	Standard	Standard
7F	Blue Ridge Parkway Corridor	CSU	CSU
7G	Pastoral Landscapes	Standard	Standard
8A1	Mix of Successional Habitats	Standard	N/A
8A1U	Mix of Successional Habitats-Unsuitable for Timber Production	Standard	N/A
8B	Early Successional Habitats	Standard	N/A
8BU	Early Successional Habitats-Unsuitable	Standard	N/A
8C	Black Bear/Remote Habitats	Standard	N/A
8CU	Black Bear/Remote Habitats-Unsuitable	Standard	N/A
8E4a	Indiana Bat-Primary Conservation	Administratively Unavailable	Administratively Unavailable
8E4b	Indiana Bat-Secondary Conservation	Timing	NSO
8E7	Shen Mtn Crest-Cow Knob Salamander	CSU	NSO
9A1	Source Water Watershed Protection	CSU	N/A
10B	Timber Production	Standard	N/A
10BU	Timber Production-Unsuitable	Standard	N/A
11	Riparian Areas and Corridors	CSU	CSU
12D	Remote Backcountry Areas	NSO	NSO
13	Mosaics of Habitat-Suitable	Standard	Standard
13U	Mosaics of Habitat-Unsuitable	Standard	N/A
	Laurel Fork Area	Administratively Unavailable	Administratively Unavailable

*Public Supply Watersheds (including the watershed upstream of the Dry River PWS) are administratively unavailable and can contain multiple management prescription areas. Portions of Rx 13 that are on Shenandoah Mountain south of Highway 250 and above 3,000 feet in elevation are NSO. Portions within Semi-Primitive Non-Motorized and Semi-Primitive Motorized settings are CSU.

Oil & Gas Activity by Alternative

The potential federal oil and gas activity on 100% federal mineral ownership for each alternative is shown in Table 3D-5 GWNF Federal Oil & Gas Lease Activity by alternative on 100% federal mineral ownership.

Table 3D-5. GWNF New Federal Oil & Gas Lease Activity by Alternative on 100% Federal Mineral Ownership

Activity	Federal 100% Mineral Ownership Baseline RFD				Alt A				Alt B			
	Exploration/ Evaluation wells (vertical)	Develop-ment wells (vertical)	Development wells (horizontal)	Total	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total
Number of wells	17	42	207	265	16	39	198	253	12	30	153	195
Roads (miles)	25	42	138	204	24	39	132	195	12	30	51	94
Roads (acres)	121	201	668	990	114	191	639	944	59	148	247	380
Well Pads (acres)	34	86	476	596	33	81	378	492	25	63	292	380
Road & Well Pads (acres)	155	287	1,144	1,586	147	272	1,017	1,436	84	210	539	833
Well pads initial reclamation (acres)	31	76	433	540	29	72	344	445	22	56	266	344
Well pads in production (acres)	4	10	36	49	4	9	34	47	3	7	26	36
Pipelines (miles)	27	46	152	225	26	43	145	214	13	33	56	103
Pipelines (acres)	72	121	401	594	69	114	383	566	35	89	148	272
Off Site Production Facilities (acres)	0	0	0	21	0	0	0	24	0	0	0	19
Production reclamation (acres)	197	331	1,105	1,654	187	314	1,057	1,581	97	243	421	781
Total reclamation (total disturbance) (acres)	228	408	1,538	2,194	216	386	1,401	2,027	120	299	687	1,125
Water use for drilling (1,000s of gallons)	332	830	20,667	21,829	315	787	19,767	20,868	244	609	15,267	16,119
Water use for hydraulic fracturing (1,000s of gallons)	6,640	16,600	1,033,350	1,056,590	6,292	15,731	988,350	1,010,373	4,871	12,177	763,350	780,397

Activity	Alts C and I				Alt D				Alt E			
	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total
Number of wells	0	0	0	0	12	30	153	195	11	27	0	37
Roads (miles)	0	0	0	0	12	30	51	93	5	13	0	19
Roads (acres)	0	0	0	0	59	147	247	453	26	65	0	91
Well Pads (acres)	0	0	0	0	25	63	292	380	22	55	0	77
Road & Well Pads (acres)	0	0	0	0	84	210	539	833	48	120	0	168
Well pads initial reclamation (acres)	0	0	0	0	22	56	266	344	20	49	0	69
Well pads in production (acres)	0	0	0	0	3	7	26	36	2	6	0	9
Pipelines (miles)	0	0	0	0	13	33	56	103	6	15	0	21
Pipelines (acres)	0	0	0	0	35	88	148	272	16	39	0	54
Off Site Production Facilities (acres)	0	0	0	0	0	0	0	19	0	0	0	18
Production reclamation (acres)	0	0	0	0	97	243	421	761	44	110	0	154
Total reclamation (total disturbance) (acres)	0	0	0	0	119	299	687	1,105	64	159	0	222
Water use for drilling (1,000s of gallons)	0	0	0	0	243	608	15,267	16,118	214	534	0	747
Water use for hydraulic fracturing (1,000s of gallons)	0	0	0	0	4,863	12,158	763,350	780,372	4,271	10,676	0	14,947

Activity	Alt F				Alt G				Alt H			
	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total	Explor/Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total
Number of wells	9	22	114	144	11	27	0	38	8	19	96	122
Roads (miles)	4	11	19	34	5	14	0	19	4	10	16	29
Roads (acres)	21	53	92	166	27	67	0	93	18	46	77	142
Well Pads (acres)	18	45	217	281	23	57	0	79	16	39	183	238
Road & Well Pads (acres)	39	98	309	446	49	123	0	173	34	85	260	380
Well pads initial reclamation (acres)	16	40	198	254	20	51	0	71	14	35	166	215
Well pads in production (acres)	2	5	20	27	3	6	0	9	2	4	17	23
Pipelines (miles)	5	12	21	38	6	15	0	21	4	10	18	32
Pipelines (acres)	13	32	55	100	16	40	0	56	11	28	46	85
Off Site Production Facilities (acres)	0	0	0	15	0	0	0	18	0	0	0	21
Production reclamation (acres)	36	90	167	292	45	113	0	158	31	78	140	250
Total reclamation (total disturbance) (acres)	52	130	364	546	65	163	0	229	45	113	307	465
Water use for drilling (1,000s of gallons)	174	436	11,367	11,978	220	550	0	769	152	381	9,567	10,100
Water use for hydraulic fracturing (1,000s of gallons)	3,489	8,722	568,350	580,561	4,397	10,992	0	15,389	3,045	7,611	478,350	489,006

Alternatives B through H identify some areas available only under No Surface Occupancy and many of the areas are relatively remote. This means that the remaining areas available for Standard or Controlled Surface Use would likely have better existing access and require fewer roads to access the well pads. Therefore, in Alternatives B and D the estimate for miles of road per well pad is changed to one mile. In Alternatives E, F, G, and H the estimate is changed to one-half mile of road per well pad.

Cumulative Oil & Gas Activity on GWNF by Alternative

The cumulative future oil and gas activity from both projected federal and private oil & gas lease activity on GWNF for each alternative is shown in Table 3D-6 GWNF cumulative oil & gas activity (projected federal and private oil & gas lease activity on GWNF).

Past oil and gas activity on the Forest consists of five oil and gas wells drilled on federal oil & gas leases during the 1970 to 2000 period; the five wells were dry holes. Currently the Forest does not have any active federal oil and gas wells. No private oil and gas wells (outstanding or reserved mineral rights) were drilled on the Forest in the past, and no private oil and gas wells are present on the Forest. The cumulative impacts from oil and gas activity would be mostly due to cumulative future oil and gas activity projected under each alternative (Table 3D-6). The cumulative future oil and gas activity has two parts. The first part is the future federal oil & gas lease activity on 100% federal mineral ownership (Table 3D-5). The second part is the future oil & gas lease activity on 1) existing federal leases and 2) private mineral rights (outstanding or reserved mineral rights). Oil and gas activity for this second part is shown under Alternatives C and I in Table 3D-6. Because no lands would be administrative available for new federal oil and gas leasing under Alternatives C and I, the only oil and gas activity under Alternatives C and I would be on existing rights (private mineral rights (outstanding or reserved mineral rights) or existing federal leases. Adding this second part activity to the each alternative's activity in the first part (Table 3D-5) yields the cumulative future oil and gas activity (Table 3D-6).

Table 3D-6. GWNF cumulative future oil & gas activity (projected federal and private oil & gas lease activity on GWNF) Table

Activity	GWNF (federal and private mineral ownerships) Baseline RFD				Alt A				Alt B			
	Exploration/ Evaluation wells (vertical)	Development wells (vertical)	Development wells (horizontal)	Total	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total
Number of wells	20	50	249	319	19	48	240	307	16	39	195	250
Roads (miles)	30	50	166	246	29	48	160	237	16	39	65	120
Roads (acres)	145	242	804	1,193	139	232	776	1,147	76	189	315	579
Well Pads (acres)	41	103	476	621	40	99	459	597	32	80	373	486
Road & Well Pads (acres)	187	346	1,281	1,814	179	331	1,235	1,744	108	269	688	1,065
Well pads initial reclamation (acres)	37	92	433	562	35	88	418	541	29	72	339	440
Well pads in production (acres)	5	12	43	59	4	11	42	57	4	9	34	46
Pipelines (miles)	33	55	183	271	32	53	176	260	17	43	72	131
Pipelines (acres)	87	145	483	716	83	139	465	688	45	113	189	348
Off Site Production Facilities (acres)	0	0	0	25	0	0	0	24	0	0	0	19
Production reclamation (acres)	237	399	1,331	1,993	227	382	1,283	1,916	124	311	538	993
Total reclamation (total disturbance) (acres)	274	491	1,764	2,555	262	470	1,700	2,457	153	383	877	1,433
Water use for drilling (1,000s of gallons)	400	1,000	24,900	26,300	383	957	24,000	25,339	312	779	19,500	20,590
Water use for hydraulic fracturing (1,000s of gallons)	8,000	20,000	1,245,000	1,273,000	7,652	19,131	1,200,000	1,226,783	6,231	15,577	975,000	996,807

Activity	Alts C and I				Alt D				Alt E			
	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total
Number of wells	3	9	42	54	16	39	195	249	14	35	42	92
Roads (miles)	5	9	28	42	16	39	65	119	7	18	7	32
Roads (acres)	25	41	137	203	75	189	315	579	34	85	34	154
Well Pads (acres)	7	18	81	106	32	80	373	486	29	73	81	183
Road & Well Pads (acres)	32	59	218	308	108	269	688	1,065	63	158	115	336
Well pads initial reclamation (acres)	6	16	74	96	29	72	339	439	26	65	74	164
Well pads in production (acres)	1	2	7	10	4	9	34	46	3	8	7	19
Pipelines (miles)	6	9	31	46	17	43	72	131	8	19	8	35
Pipelines (acres)	15	25	82	122	45	113	189	348	20	51	21	92
Off Site Production Facilities (acres)	0	0	0	4	0	0	0	19	0	0	0	18
Production reclamation (acres)	40	68	226	339	124	311	538	992	58	145	62	282
Total reclamation (total disturbance) (acres)	47	84	300	434	153	382	877	1,432	84	209	136	446
Water use for drilling (1,000s of gallons)	68	170	4,233	4,471	311	778	19,500	20,589	282	704	4,233	5,218
Water use for hydraulic fracturing (1,000s of gallons)	1,360	3,400	211,650	216,410	6,223	15,558	975,000	996,782	5,631	14,076	211,650	231,357

Activity	Alt F				Alt G				Alt H			
	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total	Explor/ Eval wells (vertical)	Develop wells (vertical)	Develop wells (horizontal)	Total
Number of wells	12	30	156	198	14	36	42	93	11	28	138	177
Roads (miles)	6	15	26	47	7	18	7	32	6	14	23	42
Roads (acres)	29	73	126	229	35	87	34	156	27	67	112	205
Well Pads (acres)	25	63	298	386	30	74	81	185	23	57	264	344
Road & Well Pads (acres)	54	136	424	615	65	162	115	341	49	124	376	549
Well pads initial reclamation (acres)	22	56	271	350	26	66	74	166	20	51	240	311
Well pads in production (acres)	3	7	27	37	3	8	7	19	3	6	24	33
Pipelines (miles)	7	17	29	52	8	20	8	35	6	15	25	46
Pipelines (acres)	18	44	76	137	21	52	21	94	16	40	67	123
Off Site Production Facilities (acres)	0	0	0	15	0	0	0	18	0	0	0	14
Production reclamation (acres)	50	125	229	418	59	148	62	287	45	113	202	374
Total reclamation (total disturbance) (acres)	72	180	500	768	86	214	136	453	66	164	442	685
Water use for drilling (1,000s of gallons)	242	606	15,600	16,449	288	720	4,233	5,240	220	551	13,800	14,571
Water use for hydraulic fracturing (1,000s of gallons)	4,849	12,122	780,000	796,971	5,757	14,392	211,650	231,799	4,405	11,011	690,000	705,416

Basic Oil & Gas Investment and Outputs by Alternative

The federal oil and gas leasing program provides natural gas and other energy minerals needed by people, and provides a source of revenue to federal and local governments. Federal oil and gas leases are issued by competitive sale. A competitive sale may generate federal revenue from a bonus bid, as well as the annual rental fees for the lease acreage. If a lease is drilled and goes into production, the federal government receives a royalty on production. The revenue generated from the federal leases is shared with all the counties on the Forest. The federal government provides the counties 25 percent of all of the revenues from federal leasing (annual rental fees, production royalties, bonus bids). Basic oil & gas investments and the resulting outputs for future federal oil & gas leases on GWNF 100% Federal Mineral Ownership are shown in Table 3D-7. Additional investments may be for such work as geophysical exploration, road and bridge upgrades, gas field maintenance and operations, and reclamation. Similarly, additional outputs would occur as federal revenue from bonus bids and annual lease rentals, State and counties 25% share of these federal revenues. Other outputs may be such items as severance tax revenue to state or counties where applicable, and *Ad valorem* property taxes on production and field equipment.

Table 3D-7. Oil & Gas Investment and Outputs on Future New Federal Oil & Gas Leases on GWNF 100% Federal Mineral Ownership[1]

Activity	RFD	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Oil & Gas Investment[2] (millions $)	$1,698	$1,623	$1,255	$0	$1,255	$93	$933	$95	$788
Natural gas production (MCF)	679,000,000	649,000,000	502,000,000	0	502,000,000	37,000,000	373,000,000	38,000,000	315,000,000
Wellhead value of natural gas production[3] (millions $)	$3,055	$2,921	$2,259	$0	$2,259	$1,67	$1,679	$171	$1,418
Federal revenue[4]: production royalty (millions $)	$382	$365	$282	$0	$282	$21	$210	$21	$177
25% share of federal royalty to States for distribution to counties for schools and roads[4] (millions $)	$95	$91	$71	$0	$71	$5	$52	$5	$44

[1] This table excludes the part of the baseline RFD and the alternatives that do not vary by alternative: 16% of federal surface underlain by private mineral rights (partial or complete mineral interest) and 1% of federal surface in current federal leases.
[2]Based on estimated average cost for completed vertical well of $2.5 million and completed horizontal well of $7.5 million
[3]Based on 15 year average of $4.50/MCF (March 1997-Feb 2012) using U.S. Energy Information Administration (2012) data
[4]Does not include federal revenue from bonus bids and annual lease rental payments

DIRECT, INDIRECT AND CUMULATIVE EFFECTS OF FEDERAL OIL AND GAS LEASING AVAILABILITY

Geologic Resources

Federal oil and gas activities that involve ground disturbance, such as construction of roads, well pads, and pipeline corridors, have the potential to adversely affect geologic resources, such as groundwater, groundwater-dependent ecosystems, springs, caves, sinkholes, karst, unusual landforms, and paleontological resources. All the alternatives with federal oil and gas leasing have the environmental protection requirements contained in federal oil and gas leases, BLM oil and gas regulations, Forest Service oil and gas regulations, State oil and gas regulations, federal laws applicable to NFS lands, and Forest Plan standards. The Forest Plan standards to protect geologic resources are in various sections of the Forest Plan, including Geologic Resources, Geologic Hazards, Water, Soil, Caves and Karstlands, and Indiana Bat Management. Standards under all alternatives provide that the location and design of management activities, including oil and gas activities, will evaluate measures to avoid, minimize, or mitigate adverse effects on geologic resources with identified values (scientific, scenic, paleontological, ecological, recreation, drinking water, groundwater and groundwater dependent ecosystems). The environmental protection requirements would avoid or reduce potential effects on the Forest's geologic resources.

The potential ground-disturbing activities associated with oil and gas activity will be used as an indicator of potential impact on geologic resources (Table 3D-5). Using this indicator, Alternatives C and I have the lowest potential for impact on geologic resources; Alternatives E, G, H, F, D and B have increasing levels of potential impact; and Alternative A has the most potential for impact on geologic resources.

In regard to karst resources (caves, sinkholes, springs, groundwater), geologic map units indicate 11% of the Forest (about 119,000 acres) have geologic formations containing karst (Figure 3A-1). These geologic map units containing karst (carbonate bedrock) are estimated to encompass 109,308 acres in Virginia and 9,906 acres in West Virginia. Karst areas may be less than 100% of the geologic map unit because other types of bedrock may be present. The Marcellus Shale occurs on about 56% of the Forest (about 592,300 acres) (Figure 3D-2). The geologic map units containing karst (11% of Forest) generally do not overlap with the Marcellus Shale (56% of Forest). The relatively small areas of overlap as well as the environmental protection requirements relating to karst would avoid or reduce potential for adverse effects on karst resources, such as damage to caves. Still, the potential for impact remains, and the greatest vulnerability to groundwater contamination is in karst terrain where spills on the ground surface could seep rapidly into the groundwater system, and where drilling and hydraulic fracturing have potential to affect karst groundwater systems. The karst terrain on or off the Forest could be affected by spills or accidents in the transport of materials to and from the well sites (including transport of flowback fluids to disposal sites off the Forest). Using potential ground-disturbing activities associated with oil and gas activity as an indicator of potential impact on karst, Alternatives C and I have the lowest potential for impact; Alternatives E, G, H, F, D and B have increasing levels of potential impact; and Alternative A has the most potential for impact on karst. Alternative H has an added protection for karst in that the cave areas identified as Special Geologic Areas are also available only with No Surface Occupancy.

Public scoping concerns about groundwater arose initially in regard to potential use of multi-stage hydraulic fracturing of horizontal wells to develop unconventional gas on future federal oil and gas leases on the Forest. Because the risk to groundwater increases with increasing exposure to the potential hazard, the number of horizontal wells using multi-stage hydraulic fracturing (Table 3D-5) can be used as one indicator of potential hazard and risk to groundwater, Alternatives C, E, G and I would have no multi-stage hydraulic fracturing horizontals wells on future federal oil and gas leases, and so, would have the least impact on groundwater. Alternatives H, F, B and D would have increasing numbers of horizontal wells, and so, an increasing level of potential impact; and Alternative A would have the most horizontal wells and the most potential for impact on groundwater.

Further concerns about groundwater were raised about the use of hydraulic fracturing in any oil and gas well (vertical or horizontal well). In addition, impacts to groundwater can occur not only during the drilling and

hydraulic fracturing process, but also during the life of a well due to development of a leak or break in the subsurface protections (such as casing and cement). Using the number of wells (vertical and horizontal wells) (Table 3D-5) as another indicator of potential hazard and risk to groundwater, Alternatives C and I would have no wells on future federal oil and gas leases, and so, would have the least potential impact on groundwater. Alternatives E, G, H, F, B and D would have increasing numbers of wells, and so, an increase in potential impact; and Alternative A would have the most wells and most potential for impact on groundwater. More analysis on potential effects on groundwater is in Water and Aquatics section.

Geologic Hazards

Geologic hazards are geologic processes or conditions (naturally occurring or altered by humans) that present a risk or potential danger to public safety, infrastructure, and resources. In addition to the types of geologic hazards discussed in Chapter 3 Section A, oil and gas activities add types of geologic hazard specific to oil and gas exploration and development, such as gas blowouts from wells, gas explosion, and gas fires, for example from damaged gas pipelines. Geologic hazards may affect or be affected by oil and gas activities, such as construction of roads, well pads, and pipeline corridors. Oil and gas activities have potential for two types of effects relating to geologic hazards:

Type 1 effect - Oil and gas activities have the potential to increase risk to public safety, infrastructure, and resources by not considering natural geologic hazards in the location, design, operation and maintenance of oil and gas activities. For example, a natural landslide may damage or destroy an access road or a gas pipeline, and injure or kill people. Different geologic settings have different geologic hazards. In karst areas, there are karst geologic hazards, including potential for ground collapse (sinkholes). If siting, design, operation and maintenance of oil and gas activities do not consider the geologic setting and potential geologic hazards, then public safety and infrastructure may be inadvertently and unnecessarily put at risk.

Type 2 effect - Oil and gas activities have the potential to increase risk to public safety, infrastructure and resources by not considering human-induced geologic hazards in the location, design, operation and maintenance of oil and gas activities. Oil and gas activities have the potential to: 1) create human-induced geologic hazards; or 2) trigger or aggravate natural geologic hazards. For example, in karst areas, oil and gas activities have the potential to contaminate groundwater and to trigger or aggravate karst geologic hazards, including potential for ground collapse (sinkholes). Another example, excavation for oil and gas access road on a steep slope can undercut and remove some support from the hillside. In some geologic settings (adverse bedrock structures or weak surficial materials), this undercut and removal of support may lead to failure of the road cut-slope and hillside upslope. Or, construction of a road fill or well pad fill on a steep, geologically unstable slope may lead to a failure of the fill-slope. A fill failure triggered during a heavy rainstorm can transform into a debris flow and travel hundreds or thousands of feet down slope, endangering people and infrastructure far away from the fill failure. If siting, design, and maintenance of oil and gas activities do not consider the geologic setting and potential geologic hazards, then public safety and infrastructure may be inadvertently and unnecessarily put at risk.

Mitigation of these potential impacts under each alternative is a challenge because there is no federal law with specific requirements that federal agencies consider the effects of ground disturbing activities on geologic hazards and associated risks to public safety.

To address the wide range of geologic hazards and to reduce the potential for impacts from oil and gas activities, the alternatives have forestwide standards that provide:

- Locate, design, and maintain trails, roads, other facilities, and management activities to avoid, minimize, or mitigate geologic hazards and potential impact on infrastructure and public safety.
- For ground-disturbing projects on slope gradients of 40% or greater located upslope and within one-half mile of Forest external boundary, conduct a geologic hazard and risk assessment of off-Forest public safety for landslides, including debris flows.
- Site characterization prior to construction on slope gradients of 40% or greater will: 1) identify existing geologic slope stability conditions; 2) evaluate how construction would alter the existing

conditions; and 3) assess potential for slope failures (from cut slopes, fill slopes, disposal sites for excess excavation, and sidecast material).

The potential ground-disturbing activities associated with oil and gas activity (Table 3D-5) will be used as an indicator of potential impact on geologic hazards. Using this indicator, Alternatives C and I have the lowest potential for impact on geologic hazards; Alternatives E, G, H, F, D and B have increasing levels of potential impact; and Alternative A has the most potential for impact on geologic hazards.

The potential future oil and gas activities from existing federal leases and private mineral rights are the same for each alternative, and so, the added potential effects on geologic resources and geologic hazards are the same for each alternative. Adding these effects to the effects from future oil and gas activities from future federal leases on 100% federal mineral ownership gives the total effects from the Forest's future oil and gas activities. Using potential ground-disturbing activities associated with oil and gas activity (Table 3D-6) as an indicator of potential effects on geologic resources including karst resources and on geologic hazards, Alternatives C and I have the lowest potential for cumulative impacts; Alternatives E, G, H, F, D and B have increasing levels of potential impact; and Alternative A has the most potential for cumulative impacts. In regard to effects on groundwater from oil and gas activities, using horizontal wells with multi-stage hydraulic fracturing as one indicator of potential impact on groundwater, Alternatives C, E, G and I would have the least impact; Alternatives H, F, B and D would have increasing levels of potential impact; and Alternative A would have the most potential for impact on groundwater. Using vertical and horizontal wells as another indicator of potential impact on groundwater, Alternatives C and I would have the least impact on groundwater; Alternatives E, G, H, F, B and D would have increasing levels of potential impact; and Alternative A would have the most potential for impact on groundwater.

Considering the oil and gas activities along with other Forest management activities (timber, recreation, etc.), the cumulative impact on geologic resources and geologic hazards is the combination of the impacts discussed in Chapter 3 Section A with the impacts discussed above.

Soils

Oil and gas lease development is likely to affect soils on a long-term basis with displacement and compaction associated with roads and well pad development and is mainly caused by the blading of these areas. Pipeline installations are likely to impact soils on a short-term basis due to the replacement of displaced soil back into the trench. Some pipeline installations will parallel roads. The soil has remained onsite and will recover with vegetative cover. Disturbed soils are prone to erosion when vegetation is removed. Erosion control plans will be implemented.

Soils could also be affected by localized spills of fluids used during the drilling process, which could sterilize the soil and affect soil productivity. Operation plans will require drilling fluids, muds and cuttings to be contained in lined ponds and removed after use. Fracking fluids will be contained in a closed loop system and will be disposed off-site.

Estimates of the effects to long-term soil productivity and how extensive they could be are shown below. A threshold for a significant impact to soil productivity will be a fifteen percent reduction in productivity across the areas on the Forest that could be affected by oil and gas lease development (activity area). When long-term soil productivity is reduced on fifteen percent or more of the activity area by any alternative, then this would be a significant impact to the soil resource and would not be in compliance with the laws guiding FS policy on protecting soil productivity. By identifying impacts to soil productivity and minimizing these impacts to small areas, we can protect the soil's ability to function as an important part of the surrounding ecosystem.

Activity areas are the areas on the Forest where oil and gas exploration and development could occur. Each alternative has a different sized activity area because alternatives vary by management area and prescription allocations. The size of the different management areas on the forest changes by alternative. In each alternative we have subtracted the acres on the Forest that will not be impacted by oil and gas development. The Activity Area for each alternative is used to compare with the total acres of long-term effect to soil productivity from oil and gas development and therefore determine the extent of the effects to soil productivity

for each alternative. In this way we can estimate the effects to the soil resource from oil and gas lease development across the Forest.

Table 3D-8. Oil and Gas Activity Areas by Alternative, thousands of acres

Category	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Total Forest acres	1,066	1,066	1,066	1,066	1,066	1,066	1,066	1,066
No development expected [1]	95	275	968	277	352	451	336	736
Total Activity Area, acres of possible development	971	791	98 [2]	789	714	615	730	330

[1] No development assumed in areas designated: No Surface Occupancy, Administratively Unavailable, Legally Unavailable and Administratively Available Decision Deferred, using Table 3D-2, Final EIS, Chapt. 3.

[2] Private mineral rights on these acres are considered possible for development.

The table below displays the estimated long-term effects to soil productivity in the areas where leasing and development will most likely occur. Long-term effects will be due to well site and road construction.

Table 3D-9. Estimated Long-Term Effects to Soil Productivity from RFD Oil and Gas Lease Development by Alternative

Category	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Acres of Long-Term Productivity Affected[1]	1744	1065	308	1065	336	615	341	549
Activity Area, acres	971,000	791,000	97,615	789,000	714,000	615,000	730,000	330,000
Percent of Area Affected Long-Term[2]	0.2%	0.1%	0.3%	0.1%	0.05%	0.1%	0.05%	0.2%

[1] Acres in Roads and Well Pads.

[2] Percent of the area most likely to be developed or activity area.

Cumulative effects add in wells and roads already constructed on the Forest for oil and gas development.

As of Feb 2013, federal oil and gas leases were in effect on about 1% of the Forest (10,412 acres). Oil and gas exploration and development on existing federal oil and gas leases can occur regardless of which alternative is chosen.

The estimated cumulative oil and gas development from projected federal and private oil & gas lease activity on GWNF for each Alternative is shown below along with cumulative effects to soils from other management activity, by alternative.

Table 3D-10. Total Cumulative Long-Term Effects to Soil Productivity from Oil and Gas Lease Development and Proposed Forest Plan Alternatives, acres

Category	Alt A	Alt B	Alt C	Alt D	Alt E	Alt F	Alt G	Alt H	Alt I
Acres of Existing Impacts from Oil and Gas Development [1]	10	10	10	10	10	10	10	10	10
Oil and Gas Lease Development Effects, Acres [2]	1,744	1,065	308	1,065	336	615	341	549	308
Total Cumulative Effects from All Other Forest Plan Activity, Acres [3]	5,376	5,106 – 5,436	4,295	5,674 – 6,194	5,041- 5,321	4,883 – 5,123	5,041 – 5,371	5,041 – 5,371	5,041 – 5,371
Total Cumulative Effect on Forest Long Term Soil Productivity, Acres	7,130	6,181 – 6,511	4,613	6,749 – 7,269	5,387- 5,667	5,508 – 5,748	5,392 – 5,722	5,600 – 5,930	5,359 – 5,689
Percentage of Activity Area with Soil Productivity Impacts ☐	0.7% of 1,021,551 acres	0.6% of 1,002,447 acres	0.7% of 636,140 acres	0.7% of 1,008,299 acres	0.5-0.6% of 998,601 acres	0.6% of 910,782 acres	0.5-0.6% of 1,002,612 acres	0.6% of 995,202 acres	0.5-0.6% of 995,202 acres

[1] Existing oil and gas long-term effects result from 5 existing well sites. Existing roads for oil and gas development are included in the effects of FS system roads, Table 3A4-3. Exploration/Evaluation Well Pad (vertical well) - (300'x300' pad): 2.07 acres per pad used for the five existing wells.
[2] Area in roads and well pads
[3] Adjusted Cumulative Long Term Effects from Table 3A4-3.
[4]Activity Area is the area on the Forest where there is potential for soil disturbance, taken from Table 3A4-1.

Estimated cumulative effects from RFD oil and gas development and proposed Forest Plan management activities are similar for all alternatives. At least 99% of the Forest's soil productivity will be maintained.

Short-term effects from compaction and erosion will be minimized through implementation of the site-specific erosion and sediment control plans developed for all construction areas. A Spill Prevention Control and Countermeasures Plan is prepared for each site to minimize the possibility and impacts from spills associated with oil and gas development. Overall, cumulative long-term effects to soil productivity from oil and gas on the George Washington NF is less than one percent of the activity area considered for each alternative. Alternatives C and I has the least acres impacted, with Alternative B having the most.

Air Quality

The George Washington National Forest is assessing the environmental consequences of leasing natural gas exploration and production rights on the Forest, under a variety of Alternatives. The primary criteria pollutant emissions from development of natural gas wells are nitrogen oxides (NO_x) and volatile organic compounds (VOC). These pollutants combine in the presence of sunlight to form ozone, a regulated pollutant that affects

human health, and vegetation. The purpose of this analysis is to examine potential air quality impacts of emissions from the proposed activities.

Air quality impacts from development of a natural gas field can be divided into two categories: construction of well sites and production/operation of the wells. These activities differ in that the construction phase is relatively short, while the production phase will persist as long as the well continues to produce gas.

Construction Emissions: Construction emissions include the pollutant emissions from well pad development, which involves three separate, sequential activities: 1) Clearing, grading and construction of the road that connects the existing access road to the well pad site. These activities are sources of fugitive dust emissions from the construction traffic over unpaved roads, and tailpipe emissions from the construction traffic. 2) Rig-up, drilling and rig-down. These activities consist of bringing equipment and supplies by truck to the well site, drilling a hole to the desired depth, and removing the drilling equipment. Pollutant emissions from this phase of activity include particulates from the traffic on unpaved roads, tailpipe emissions from trucks, and exhaust emissions from the diesel powered drilling engines. 3) Completion and testing involves running pipe into the borehole and flaring small quantities of gas at the surface to evaluate productivity of the well. Pollutant emissions that occur during completion and testing include road dust from truck traffic, tailpipe emissions from the trucks, and products of combustion from flaring natural gas. It was assumed that each well would require construction of a separate well pad.

Production Emissions: Gas produced from leased wells on the Forest will be collected and piped to a compressor station located on private land. The main source of emissions from the production phase will be from fugitive equipment emissions. Lesser emissions come from the heater-separator that is designed to separate liquids from the gas stream. Heat comes from burning some of the methane produced from the well.

The emission rates for construction and production activities have been taken from a Bureau of Land Management report "Environmental Assessment: Cooper Reservoir Natural Gas Development Project - Cumulative Air Quality Impact Analysis, May 1998". The Cooper Reservoir Project activities were similar to what would occur in gas field development in southwestern Virginia, which made it possible to use the pre-calculated, construction phase emissions for this analysis. Activities were of similar duration, similar equipment was used, and both projects involved "sweet" gas. Sweet gas wells do not produce hydrogen sulfide gas during flaring.

Analysis: Although the Reasonably Foreseeable Development report by BLM indicates that only a portion of the total wells will be constructed each year, this analysis assumed that construction and production for all wells would occur in one year. This approach provides a “worst case” assessment of potential impacts on air quality. In reality, all development scenarios would produce impacts less than presented here.

Each Alternative has a specified maximum number of wells that could be put into production over the next 15 years. Nitrogen oxide and volatile organic compound emissions from construction and production are calculated and compared between Alternatives for the “Direct/Indirect Effects” analysis. Future emissions from private wells on national forest system lands are added to the emissions from the Direct/Indirect effects analysis to assess "Cumulative Effects". Projected emissions are then compared to the current emission inventory (existing area and point sources of pollution, EPA 2005) for a ten-county analysis area to estimate the future potential effect on air quality. The analysis area includes counties with underlying Marcellus shale: Alleghany, Augusta, Bath, Botetourt, Highland, Rockbridge and Rockingham in Virginia; and Hampshire, Hardy and Pendleton in West Virginia.

Direct/Indirect Effects: The direct effect on air quality of leasing national forest land for gas development will be to increase volatile organic compounds and nitrogen oxides in the atmosphere by a very small amount (Table 3D-11). Maximum annual emissions from “leased wells” would contribute 99 tons per year of VOC; less than 0.4% of current emissions in the analysis area (20,316 tons). Nitrogen oxide emissions are similar; maximum of 89 tons per year which is only 0.39% of current emissions (22,838 tons).

Table 3D-11. Maximum Estimated Annual Air Pollution Emissions from Projected Gas Well Development on the GWNF, tons

Alternative	Direct Effects		Cumulative Effects	
	Volatile Organic Compounds	Nitrogen Oxide	Volatile Organic Compounds	Nitrogen Oxide
A	81	89	99	108
B	63	69	80	88
C and I	0	0	17	19
D	63	69	80	88
E	12	13	29	32
F	46	51	64	70
G	12	13	30	32
H	39	43	57	62
BLM RFD	85	93	102	112
Current Emissions in Tons (EPA 2005 Emissions Inventory)			20,316	22,838

There are differences in air pollution emissions between some of the alternatives, but in all cases emissions are such a small portion of the overall pollution load that all alternatives would have very little effect on air quality.

These estimates of volatile organic compounds are likely high since they do not take into account the new regulations from EPA. On April 17, 2012, the U.S. Environmental Protection Agency (EPA) issued regulations to reduce air pollution from natural gas wells that are hydraulically fractured. A key component of the final rules is expected to yield a nearly 95 percent reduction in VOCs emitted from more than 11,000 new hydraulically fractured gas wells each year. This significant reduction would be accomplished primarily through the use of "green completion" -- to capture natural gas that currently escapes to the air. In a green completion, special equipment separates gas and liquid hydrocarbons from the flowback that comes from the well as it is being prepared for production. The gas and hydrocarbons can then be treated and used or sold, avoiding the waste of natural resources that cannot be renewed.

The VOC emission reductions from wells, combined with reductions from storage tanks and other equipment, are expected to help reduce ground-level ozone in areas where oil and gas production occurs. In addition, the reductions would yield a significant environmental co-benefit by reducing methane emissions from new and modified wells. Methane, the primary constituent of natural gas, is a potent greenhouse gas – more than 20 times as potent as carbon dioxide when emitted directly to the atmosphere. The final rules also would protect against potential cancer risks from emissions of several air toxics, including benzene.

Cumulative Effects: The cumulative effects air analysis included emissions from 1) wells that will be developed from existing leasing rights on national forest land, 2) private-rights wells developed on national forest land, and 3) wells projected for the various Alternatives. Projected emissions from all wells that could be developed in the ten-county area are displayed in Table 3D-9 under "Cumulative Effects". Emissions from all projected development would equal less than 1% of current inventory of VOC and NO_x emissions. Both of these pollutants contribute to the formation of ozone, a criteria pollutant monitored by state air regulators. It is unlikely that the emissions from any of the projected Alternatives would affect ozone attainment status at monitors in the region because the additional emissions are such a small component of overall emissions.

For general information on air quality regulations and current air quality on the Forest see the Affected Environment: Air section of the EIS.

Water Resources and Aquatic Species

The Reasonably Foreseeable Development (RFD) of federal oil and gas on the GWNF is concentrated in the Marcellus shale formation, thus, this analysis will concentrate on potential development of that formation. This includes both vertical and horizontal well development. Horizontal well development has not yet been utilized on the GWNF. To evaluate and develop the Marcellus Shale for natural gas production, horizontal wells will undergo a stimulation process known as hydraulic fracturing, which functions to release gas embedded in shale deep below the surface. In addition, a well may be re-stimulated every five years after the initial fracturing. It is estimated that it takes up to 3-5 million gallons of water per hydraulic fracturing event for each well (Harper 2008) and one drilling site could contain several wells. Some references suggest that up to 8 million gallons of water may be needed per treatment. Flowback water is the fluid that is recovered from the well following hydraulic fracturing. Gelling agents, surfactants and chlorides are identified as the flowback water components of greatest environmental concern. Other flow back components can include other dissolved solids, metals, biocides, lubricants, organics and radionuclides. The RFD estimated 3 wells could be drilled per pad. The following are issues related to water resources and aquatic species and habitat:

- Water withdrawals
- Surface water and groundwater contamination
- Non-point source pollution from ground disturbing activities

The following indicators will be used to reflect the potential risk to watershed, riparian and aquatic resources and the differences between alternatives.

- Percent Marcellus shale on GWNF and private land by watershed, associated with TESLR (Threatened, Endangered, Sensitive and Locally Rare)/MIS (Management Indicator Species)/SMC (Species of Management Concern) aquatic species
- Miles of perennial, intermittent, and trout streams on the GWNF underlain by Marcellus shale
- Percent Marcellus shale by public water supply watershed
- Percent Marcellus shale by source water watershed (applicable to Alternative C)
- Number of potential wells, acres of disturbed areas, and water use by alternative

There are 592,300 acres of Marcellus shale under the Forest land (55.6% of land status). About 16% of the Forest is in outstanding or reserved mineral rights, with 58% of that in Marcellus shale. Only 1 % of the Forest (10,243 acres) is under existing federal oil and gas lease, all of which is within the Marcellus shale formation. Table 3D-12 lists the percent Marcellus shale found in each 5th level HUC watershed, along with the number of aquatic TESLR/MIS/SMC species by watershed. Columns 5-6 indicate the acres or percent of private subsurface ownership on the GWNF, while column 7 includes private land, since those are areas of limited or no Forest Service control. See Appendix J for a table of the complete list of species by watershed.

Table 3D-12. Marcellus Shale and Number of Aquatic TESLR/MIS/SMC by Watershed*

Watershed	Marcellus Acres on GWNF	Marcellus % of watershed on GWNF	Marcellus % of watershed on NF & Private land	Acres of Marcellus in private sub-surface on GWNF	% of watershed, Marcellus in private sub-surface on GWNF	Marcellus % of watershed: private, plus private sub-surface on GWNF	Number of aquatic TESLR/MIS/SMC
North Fk South Br Potomac	10,384	5.1%	71.3%			66.2%	21
South Fk South Br Potomac	55,525	30.1%	90.5%	12,393	6.7%	67.1%	2
Cacapon River	5,484	2.1%	66.9%	3,964	1.5%	66.3%	3
Middle River	22,543	9.4%	11.0%	2,777	1.2%	2.8%	1
Dry River-North River	110,980	58.9%	67.8%	32,557	17.3%	26.2%	4
Naked Cr-South Fk Shenandoah	1,331	0.6%	0.9%	1,026	0.5%	0.8%	5
Shoemaker R-N Fk Shenandoah	61,945	46.5%	87.8%	26,382	19.8%	61.1%	3
Smith Cr-North Fk Shenandoah	333	0.2%	5.4%			5.2%	4
Stony Cr-North Fk Shenandoah	4,906	2.2%	20.2%	1,394	0.6%	18.6%	7
Cedar Creek	422	0.4%	32.7%			32.3%	3
Dunlap Creek	37,679	34.8%	73.6%	707	0.7%	39.5%	2
Potts Creek	12,529	11.3%	47.8%			36.5%	7
Back Creek-Jackson River	55,586	25.2%	45.0%	3,999	1.8%	21.6%	5
Wilson Creek-Jackson River	22,436	16.2%	44.7%	1,152	0.8%	29.3%	8
Cowpasture River	95,086	42.0%	71.9%	10,077	4.5%	34.4%	11
Catawba Creek-James River	6,955	3.3%	22.1%	1,298	0.6%	19.4%	7
Craig Creek	1,259	0.5%	62.1%			61.6%	11
Calfpasture River	69,850	46.3%	72.5%	1,539	1.0%	27.2%	7
Little Calfpasture River	14,974	28.0%	65.2%			37.2%	1

*Birds and non-TE plants were not included in this analysis because species occurrence locations were not readily available in GIS format.

Looking at stream type underlain by Marcellus shale on the GWNF; there are 792 miles of perennial streams, 1,596 miles of intermittent streams, and 426 miles of trout water (VDGIF 2010a).

Table 3D-13 lists the acres and percentages of Marcellus shale in public water supply watersheds, by ownership pattern. Table 3D-14 shows the acres and percentages of Marcellus shale in the source water watersheds used in Alternative C.

Table 3D-13. Marcellus Shale by Public Water Supply Watershed

Public Water Supply Watershed	Acres of Marcellus on GWNF	Marcellus % of watershed on GWNF	Marcellus % of watershed on GWNF & Private land	Acres of Marcellus in private sub-surface on GWNF	% of watershed, Marcellus in private sub-surface on GWNF	Marcellus % of watershed: private, plus private sub-surface on GWNF
North Fork Shenandoah River-Cedar Creek	402	0.4%	32.0%			31.5%
Dry River and Skidmore Fork	19,959	91.8%	100.0%	7,623	35.1%	43.3%
North River	16,699	100.0%	100.0%	2,270	13.6%	13.6%
Smith Creek	457	5.1%	5.7%	64	0.7%	1.3%
Jackson River	17	0.4%	69.4%			68.9%

Table 3D-14. Private Marcellus Shale by Source Water Watersheds used in Alternatives C

Source Water Watershed	Acres of Marcellus in private sub-surface on GWNF	% of watershed, Marcellus in private sub-surface on GWNF	Marcellus % of watershed: private, plus private sub-surface on GWNF
Painter Run-Stony Creek	41	0.1%	3.5%
Crab Run	2,722	14.9%	82.6%
Runion Creek-North Fork Shenandoah River	938	4.6%	62.6%
German River	6,083	30.5%	81.5%
Riles Run-Stony Creek	574	1.7%	56.8%
Little Dry River	6,251	31.1%	51.7%
Capon Run-North Fork Shenandoah River	1,812	5.8%	39.3%
Yellow Spring Run-Stony Creek	762	6.9%	32.1%
Shoemaker River	8,548	36.5%	66.5%
Honey Run-Dry River	68	0.7%	16.1%
Skidmore Fork-Dry River	10,273	41.3%	56.5%
Thorny Branch-North River	3,362	11.8%	26.2%
Black Run-Dry River	10,121	46.3%	53.5%
Little River	2,573	15.8%	18.4%
Briery Branch	659	2.1%	11.7%
Skidmore Fork-North River	4,559	18.0%	18.4%
Muddy Creek	951	4.7%	17.5%
Chair Draft-Calfpasture River	1,341	9.3%	24.4%
Hamilton Branch	192	1.6%	19.5%

The RFD estimates a total of 319 wells within the Marcellus formation (20 vertical exploration wells, 50 vertical development wells, and 249 horizontal development wells). Associated activities include: 246 miles of roads, 621 acres of well pads, 271 miles of pipeline, 26,300,000 gallons of water for drilling, and 1,273,000,000 gallons of water for fracturing. As previously stated, water withdrawals, ground and surface water contamination, and non-point source pollution from ground disturbing activities are issues of concern in relation to water resources and aquatic species.

General Effects from Water Withdrawals

Water for hydraulic fracturing will need to be trucked in, or withdrawn from nearby streams or aquifers. Without proper controls on the rate, timing and location of withdrawals, stream flow modifications could result in negative impacts to a stream's best uses, including but not limited to the aquatic ecosystem, downstream riverine and riparian resources, wetlands, and aquifer supplies. See *Appendix I - Analysis of Concerns and Risks of Horizontal Drilling and Hydraulic Fracturing*, for additional concerns regarding water withdrawals.

Impacts to Aquatic Ecosystems

Aquatic ecosystems could be adversely impacted by:

- changes to water quality or quantity;
- insufficient stream flow for aquatic biota or to maintain stream habitat; or
- the actual water withdrawal infrastructure.

Many small headwater streams on the Forest undergo severe flow reductions during the summer and early fall, making them very susceptible to further water reductions. Drawing production water from these streams could cause reductions in fish and other aquatic organism populations or damage them permanently (Vokoun and Kanno 2009). Similarly, massive withdrawals of groundwater in these headwater watersheds could adversely affect surface water flow (PSU 2009; NYDEC 2009).

Seasonally, unmitigated withdrawals could adversely impact fish and wildlife health due to exposure to unsuitable water temperature and dissolved oxygen concentrations. It could also affect downstream dischargers whose effluent limits are controlled by the stream's flow rate. Water quality could be degraded and exert greater impacts on natural aquatic habitat if existing pollutants from point sources (e.g. discharge pipes) and non-point sources (e.g. runoff from farms and paved surfaces) are not sufficiently diluted or become concentrated.

Improperly installed water withdrawal structures can result in the entrainment of aquatic organisms, which can remove any/all life stages of fish and macroinvertebrates from their natural habitats as they are withdrawn with water. To avoid adverse impacts to aquatic biota from entrainment, intake pipes can be screened to prevent entry into the pipe. Additionally, the loss of biota that becomes trapped on intake screens, referred to as impingement, can be minimized by properly sizing the intake to reduce the flow velocity through the screens. Transporting water from the water withdrawal location for use off-site can transfer invasive species from one waterbody to another via trucks, hoses, pipelines, and other equipment. Screening of the intakes can minimize this transfer; however additional site-specific mitigation considerations may be necessary.

Impacts to Downstream Wetlands

The existence and sustainability of wetland habitats directly depend on the presence of water at or near the surface of the soil. The functioning of a wetland is driven by the inflow and outflow of surface water and/or groundwater. As a result, withdrawal of surface water or groundwater for high volume hydraulic fracturing could impact wetland resources. These potential impacts depend on the amount of water within the wetland, the amount of water withdrawn from the catchment area of the wetland, and the dynamics of water flowing into and out of the wetland. Even small changes in the hydrology of the wetland can have significant impacts on the wetland plant community and on the animals that depend on the wetland. It is important to preserve the hydrologic conditions and to understand the surface water and groundwater interaction to protect wetland areas.

Aquifer Depletion

The primary concern regarding groundwater withdrawal is aquifer depletion that could affect other uses, including nearby public and private water supply wells. This includes cumulative impacts from numerous groundwater withdrawals and potential aquifer depletion from the incremental increase in withdrawals if groundwater supplies are used for hydraulic fracturing. Aquifer depletion may also result in aquifer compaction which can result in localized ground subsidence. Aquifer depletion can occur in both confined and unconfined aquifers.

The depletion of an aquifer and a corresponding decline in the groundwater level can occur when a well, or wells in an aquifer are pumped at a rate in excess of the recharge rate to the aquifer. Essentially, surface water and groundwater are one continuous resource; therefore, it also is possible that aquifer depletion can occur if an excessive volume of water is removed from a surface water body that recharges an aquifer. Such an action would result in a reduction of recharge which could potentially deplete an aquifer.

Aquifer depletion can lead to reduced discharge of groundwater to streams and lakes, reduced water availability in wetland areas, and corresponding impacts to aquatic organisms that depend on these habitats. Flowing rivers and streams are merely a surface manifestation of what is flowing through the shallow soils and rocks. Groundwater wells impact surface water flows by intercepting groundwater that otherwise would enter a stream. In fact, many headwater streams rely entirely on groundwater to provide flows in the hot summer months. It is therefore important to understand the hydrologic relationship between surface water, groundwater, and wetlands within a watershed to appropriately manage rates and quantities of water withdrawal.

Depletion of both groundwater and surface water can occur when water withdrawals are transported out of the basin from which they originated. These transfers break the natural hydrologic cycle, since the transported water never makes it downstream nor returns to the original watershed to help recharge the aquifer. Without the natural flow regime, including seasonal high flows, stream channel and riparian habitats critical for maintaining the aquatic biota of the stream may be adversely impacted. Surface and subsurface sources of public and private water supply may be reduced.

General Effects from Surface Water and Groundwater Contamination

See *Appendix I - Analysis of Concerns and Risks of Horizontal Drilling and Hydraulic Fracturing*, for additional concerns regarding, and specific examples of surface and groundwater contamination.

Surface Spills and Releases at the Well Pad

Contamination of surface water bodies and groundwater resources during well drilling could occur as a result of failure to maintain stormwater controls, ineffective site management and surface and subsurface fluid containment practices, poor casing construction, or accidental spills and releases. Surface spills would involve materials and fluids present at the site during the drilling phase. Spills or releases can occur as a result of tank ruptures, equipment or surface impoundment failures, overfills, vandalism, accidents (including vehicle collisions), ground fires, or improper operations. Spilled, leaked or released fluids could flow to a surface water body or infiltrate the ground, reaching subsurface soils and aquifers. Pit leakage or failure could also involve well fluids. The greater intensity and duration of surface activities associated with well pads with multiple wells increases the odds of an accidental spill, pit leak or pit failure if mitigation measures are not sufficiently durable. Concerns are heightened if on-site pits for handling drilling fluids are located in primary and principal aquifer areas, or are constructed on the filled portion of a cut-and-filled well pad.

Hydraulic Fracturing Additives and Flowback Water

As with the drilling phase, contamination of surface water bodies and groundwater resources during well stimulation could occur as a result of failure to maintain stormwater controls, ineffective site management and surface and subsurface fluid containment practices, poor well construction and grouting, or accidental spills and releases. These issues are acknowledged here because of the larger volumes of fluids and materials to be managed for high-volume hydraulic fracturing.

Flowback water is the fluid that is recovered from the well following hydraulic fracturing. Gelling agents, surfactants and chlorides are identified as the flowback water components of greatest environmental concern. Other flow back components can include other dissolved solids, metals, biocides, lubricants, organics and radionuclides. The exact characteristics and quantities of components in flowback water will vary by location. The additives are proprietary information and unavailable for analysis.

Opportunities for spills, leaks, operational errors, and pit or surface impoundment failures during the flowback water recovery stage are the same as they are during the prior stages with the additional potential of releases from:

- hoses or pipes used to convey flowback water to tanks, an on-site pit, a centralized surface impoundment, or a tanker truck for transportation to a treatment or disposal site; and
- tank leakage or failure of a pit or surface impoundment to effectively contain fluid.

As much as 60–80% of the hydraulic fracturing water can return to the surface (Staaf and Masur 2009) contaminated with tens of thousands of pounds of chemicals, salt, and sand. This wastewater is stored in holding ponds, potentially adjacent to perennial or intermittent stream channels and is subject to overflow, leakage, or spillage. Contact with adjacent waterways could cause fish kills or affect entire food webs and could contaminate drinking water sources. All of these streams have floodplains and, often, a complex series of dry flood channels that are sensitive to disturbances in these areas. The majority of incidents that lead to surface water contamination result from spills and leakage during the transfer and draining of these pits (NYDEC 2009).

Contaminated flowback water that is trucked off the drilling site to local wastewater treatment plants may not be able to be effectively treated (Soeder and Kappel 2009; Levy and Smith 2010) and, in fact, might render the plant useless (by killing off active media). Sand, salt, and a mixture of biocides, surfactants, lubricants, and solvents may pass through these treatment plants directly into larger rivers. Many of these rivers are already under stress from other contaminants and this would potentially add to pollution troubles (VDGIF 2010).

Land application of contaminated flowback water and solids have been known to sterilize soils and kill forest plots. At the very least, flowback water is known to contain high levels of chloride; chlorides have a number of biological and non-biological effects. Chloride ions pass readily through soil and will eventually enter surface water. Because chloride moves through soil at the same rate as water it shares the same hydrologic cycle as water. This means chloride deposited on soil's surface can also enter ground water (Environment Canada 2001). Sodium chloride is inhibiting to soil bacteria at about 50 mg/l. High concentrations of chloride will damage or kill leaves or buds when delivered as a spray. Concentrations first will affect sensitive vegetation and trees. High enough concentrations will sterilize soil and prohibit any growth (Siegal 2007).

Millions of gallons of contaminated flowback water can remain in the ground during and after production. Extra steel and concrete casing is required in wells to protect groundwater; however, corrosive agents used in slickwater frac could erode casings and contaminate entire aquifers. Many of these shale deposits are adjacent to limestone geology, thus residual frac water under pressure could find its way into groundwater supplies.

Fuel oil, surfactants, and biocides are also used in slickwater frac and this gelatinous mixture has the potential to fill fissures underground and create pollution issues. Although it is surmised that these compounds comprise only a small fraction of the fracturing fluid, it becomes additive when millions of gallons of water are pumped into the ground. This could add up to hundreds of pounds of chemicals over the production life of a well (Soeder and Kappel 2009).

Concentrated solids, contaminated with radioactive waste (i.e. radium) are often extracted from the ground after being used to fracture the shale. Some frac water in New York State exceeded the EPA safety standards for radioactivity. However, more study is needed to determine the potential impacts of radioactive materials on aquatic organisms (Sumi 2008; Rabb 2010).

Centralized Flowback Water Surface Impoundments

Use of centralized surface impoundments and flowback water pipelines as part of a flowback water dilution and reuse system has environmental benefits, including reduced demand for fresh water, reduced truck traffic and reduced need for flowback water treatment and disposal. However, any proposal for their use requires that the potential impacts be recognized and mitigated through proper design, construction, operation, closure and regulatory oversight.

- Potential soil, wetland, surface water and groundwater contamination from spills, leaks or other failure of the impoundment to effectively contain fluid. This includes problems associated with liner or construction defects, unstable ballast or operations-related liner damage.
- Potential soil, wetland, surface water and groundwater contamination from spills or leaks of hoses or pipes used to convey flowback water to or from the centralized surface impoundment.
- Potential for personal injury, property damage or natural resource damage similar to that from dam failure if a breach occurs.
- Transfer of invasive plant species by machinery and equipment used to remove vegetation and soil.
- Consumption by waterfowl and other wildlife of contaminated plant material on the inside slopes of the impoundment.

General Effects from Non-point Source Pollution from Ground Disturbing Activities

See *Appendix I - Analysis of Concerns and Risks of Horizontal Drilling and Hydraulic Fracturing*, for additional concerns regarding, and specific examples of non-point source pollution from ground disturbing activities.

All phases of natural gas well development, from initial land clearing for access roads, equipment staging areas and well pads, to drilling and fracturing operations, production and final reclamation, have the potential to cause water resource impacts during rain and snow melt events if stormwater is not properly managed.

Initial land clearing exposes soil to erosion and more rapid runoff. Construction equipment is a potential source of contamination from such things as hydraulic, fuel and lubricating fluids. Equipment and any materials that are spilled, including additive chemicals and fuel, are exposed to rainfall, so that contaminants may be conveyed off-site during rain events if they are not properly contained. Steep access roads, well pads on hill slopes, and well pads constructed by cut-and-fill operations pose particular challenges, especially if an on-site drilling pit is proposed.

A production site, including access roads, is also a potential source of stormwater runoff impacts because its hydrological characteristics may be substantially different from the pre-developed condition. There is a greater potential for stormwater impacts from a larger well pad during the production phase, compared with a smaller well pad for a single vertical well.

Each drilling pad occupies 2-6 acres of ground, not including roads and pipelines. Several pads can occupy one site, creating the potential for a significant volume of non-point runoff (NYDEC 2009). Fugitive dust may be problematic for adjacent waterways.

Cumulative Impacts

Cumulative impacts are the effects of two or more single projects considered together. Adverse cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time. Since gas production declines rapidly after the first year of well stimulation, the potential to re-stimulate the gas-producing geologic formation with another hydraulic fracturing may be considered. This second

hydraulic fracturing would use the same well and may use similar volumes of water as the first hydraulic fracturing, multiplying effects through time. Cumulative impacts will be discussed from two perspectives:

1) Site-Specific cumulative impacts beyond those previously discussed resulting from multi-well pads and

2) Regional impacts which may be experienced as a result of gas development.

Site-Specific Cumulative Impacts

The potential for site-specific cumulative impacts as a result of multi-well pads, while real, is easily quantified and can be adequately addressed during the application review process (NYDEC 2009). General areas of concern with regard to water use, ground disturbance, and contamination issues are the same as those of individual well pads. While the pads may be slightly larger than those used for single wells, the significant impacts are due to the cumulative time and trucking necessary to drill and stimulate each individual well.

In relation to non-point source pollution and surface water contamination, maintenance of the roads and accidental vehicular spills is a concern because of the number and size of the trucks used to transport and deliver equipment and supplies. A horizontal well takes four to five weeks of 24-hour-per-day drilling with an additional three to five days for the hydraulic fracture. This duration will be required for each well, with industry indicating that it is common for three wells to be drilled on a multi-well pad. Typically, one or two wells are drilled and stimulated and then the equipment is removed. If the well(s) are economically viable, the equipment is brought back and the remaining wells drilled and stimulated. Current regulations require that all wells on a multi-well pad be drilled within three years of starting the first well. As industry gains confidence in the production of the play, there is the possibility that all wells on a pad would be drilled, stimulated and completed consecutively.

The trucking requirements for rigging and equipment will not be significantly greater than for a single well pad, especially if all wells are drilled consecutively. Water and materials requirements, however, will greatly increase the amount of trucking to a multi-well pad compared to a single well pad. The NYDEC estimated truck trips per an eight well multi-well pad; those estimates were scaled back to 3 wells per pad and are as follows:

- Drill Pad and Road Construction Equipment 10 – 25 Truckloads
- Drilling Rig 20 Truckloads
- Drilling Fluid and Materials 100-200 Truckloads
- Drilling Equipment (casing, drill pipe, etc.) 100-200 Truckloads
- Completion Rig 15 Truckloads
- Completion Fluid and Materials 40-80 Truckloads
- Completion Equipment – (pipe, wellhead) 5 Truckloads
- Hydraulic Fracture Equipment (pump trucks, tanks) 150-200 Truckloads
- Hydraulic Fracture Water 1,600 – 2,400 Tanker Trucks
- Hydraulic Fracture Sand 80 – 100 Trucks
- Flow Back Water Removal 800 – 1,200 Tanker Trucks

Total estimates are 2,920–4,445 truck trips per 3 well pad. As can be seen, the vast majority of trucking is involved in delivering water and removing flow back. Multiple wells in the same location provide the potential to reduce this amount of trucking by reusing flow back water for the stimulation of other wells on the same pad. The centralized location of water impoundments may also make it economically viable to transport water via pipeline or rail in certain instances.

In the production phase, the operations at multi-well pads include a small amount of equipment, including valves, meters, dehydrators and tanks remaining on site, which may be slightly larger than what is used for single wells but is still minor. The reclamation procedures are the same as for single well pads, however, there will be more area left for production equipment and activities. It is anticipated that a multi-well pad will require up to three acres compared to one acre or less for a single well pad.

Regional Cumulative Impacts

The level of impact on a regional basis will be determined by the amount of development and the rate at which it occurs. Accurately estimating this is inherently difficult due to the wide and variable range of the resource, rig, equipment and crew availability, permitting and oversight capacity, leasing, and most importantly, economic factors. This holds true regardless of the type of drilling and stimulation utilized. In other plays around the country, development has occurred in a sequential manner over years with development activity concentrated in one area then moving on with previously drilled sites fully or partially reclaimed as new sites are drilled. Once drilling and stimulation activities are completed and the sites have been reclaimed, the long-term impact at the sites will consist of widely spaced and partially re-vegetated production sites and fully reclaimed plugged and abandoned well sites. However, for aquatic resources, there are areas of concern for cumulative impacts with regard to water use, ground disturbance, and contamination issues. The discussions below are examples of regional effects from these areas of concern.

Evaluation of cumulative impacts of multiple water withdrawals must consider the existing water usage, the non-continuous nature of withdrawals and the natural replenishment of water resources. Concerns over decreased streamflow from regional water withdrawals and the potential effect this has on aquatic habitat, water quality, and recreational use of rivers has prompted recent research in the East. In Massachusetts, cumulative withdrawal of ground water substantially decreased low flows in the Ipswich River (USGS 2001); while research in this and other rivers documented measurable alterations in fish communities following water withdrawal induced habitat changes (Armstrong et al. 2001; Freeman 2005; Vokoun and Kanno 2009). In addition to stream effects, the USGS reports that land subsidence due to the pumping of ground water occurs in nearly every State (USGS 1995).

Regional cumulative effects of water contamination and sedimentation to aquatic organisms have been documented for many species. The adverse modification and destruction of aquatic habitats, water pollution, and the introduction of non-indigenous species, have been the major causes of mussel declines and extinctions during this century (Stein et al. 2000). Of all the factors contributing to the jeopardized status of Southeastern native freshwater fishes, non-point source pollution (primarily siltation) and alteration of flow regimes (primarily impoundment) are the largest contributors to fish imperilment. Etnier (1997) points out that these two anthropogenic factors are responsible for 72% of imperilment problems.

Freshwater mussel and fish populations have been reduced and, in some cases, completely extirpated from lakes and streams by pollutants from municipal, industrial, and agricultural sources. Effluents impacting aquatic organisms include industrial discharges, fly ash and sulfuric acid spills, acid mine drainage, organic wastes, insecticides, and chlorinated sewage (USDI Fish and Wildlife Service 1990). In addition, sub-lethal bioaccumulation of toxins can reduce overall health and fitness of an individual or population. Fish advisory warnings are currently in place on five river reaches in Virginia (for mercury, PCBs, and kepone) (FORVA 2001).

Alternative Comparison

Common to all alternatives are 1) private mineral rights on NFS lands, and 2) existing federal oil and gas leases. The potential federal oil and gas activity on 100% federal mineral ownership will vary by alternative. See the Federal Oil and Gas Leasing Availability Decision by Alternative discussion in the EIS for more detail regarding federal and private ownership, current leases, and proposed stipulations. For alternative comparison in light of water resources and aquatic species, Table 3D-6 shows projected activity for both federal and private oil and gas leases.

Because the only drilling that would be done in Alternatives C and I is that under private ownership and existing federal leases, Alternatives C and I has the lowest potential for ground-disturbing activities, and least amount of water use. Those numbers are slightly higher in Alternatives E and G, because although they allow vertical wells, these alternatives exclude horizontal drilling, significantly decreasing the amount of water use and potential for contamination. Alternative H has the next highest numbers, followed by F, D and B. Lastly, Alternative A most closely corresponds to the RFD and has the highest potential for ground disturbance and uses the most amount of water.

Alternative H would allow no surface water or groundwater withdrawals from National Forest System lands unless an analysis showed that the overall impacts of the drilling could be reduced through the use of withdrawals from the Forest. Alternative H would also require closed loop systems for hydraulic fracturing and the use of a secondary containment system to reduce the risk of spills entering the stream system. It would also make public water supply watersheds (including the watershed upstream of the Dry River PWS) administratively unavailable for leasing. The result is that Alternative H would have the lowest potential for impacts on water and aquatic systems among the alternatives that allow horizontal drilling.

Under Alternative H, the application of forestwide standards and resource protection measures are designed to limit the extent and duration of adverse environmental effects. The allocation of lands to management prescriptions, the decisions on lands administratively available for leasing, and the decisions on leasing stipulations (like No Surface Occupancy) limit the exposure of the most sensitive resources to the risk of adverse environmental impacts. The record of declining violations in Pennsylvania is encouraging and many state and federal agencies are developing improved regulations to respond to past incidents. However, the record from drilling in other states indicates that there will be accidents, improper implementation of control measures and unintended actions that result in impacts to aquatic resources (see *Appendix I - Gas Drilling Concerns*).

In addition to accidents, the mountainous terrain results in the potential for increased erosion and sedimentation from soil disturbances associated with road and well pad construction, and associated facilities and pipelines. These effects can be long-term as they involve land use conversion from forest to non-forest with a loss of soil productivity and natural landform. There is also the potential for increased runoff on compacted soils which could cause changes to streamflow volumes and timing of flows. Some level of sediment from roads will reach streams and wetlands and could impact the physical characteristics and biological integrity of water resources.

Under all alternatives where horizontal drilling is allowed, some level of adverse effects to the above resources is likely unavoidable and it is important to note actual effects do not occur until project-level decisions are implemented. If we assume that newly developed regulations and control measures cut violations in half, we can still expect five to ten percent of wells to have problems. Of these from three to twenty-five percent of the wells could cause major impacts (see *Appendix I – Analysis of Concerns and Risks of Horizontal Drilling and Hydraulic Fracturing*). This would translate to about one to two wells. While this is a small amount, the previously identified extent of the sensitive aquatic resources could still result in impacts to miles of streams serving sensitive aquatic resources. In addition, it assumes a level of compliance with regulations and lack of accidents that has not yet been demonstrated. This level of impact generates concerns that require the continued search for improved control measures and greater oversight to reduce unintended actions during implementation.

Aquatic Viability Determinations for Oil and Gas Leasing

Within the Forest Plan Revision analysis, separate viability determinations were made for each watershed where a species occurs, because in many cases watersheds support separate populations, and because factors affecting viability can vary considerably from watershed to watershed. Viability outcomes from each species by watershed were determined by incorporating elements of species distribution, abundance, and sensitivities to environmental factors; watershed condition relative to the species' environmental sensitivities; and the national forest role in the watershed. To include the effects from oil and gas leasing, the amount of Marcellus shale by species and watershed was determined, as well as whether or not the species occurrence was on federally or privately owned mineral rights (see Table J1 Appendix J). Only those species found in watersheds with Marcellus shale were included. Viability outcomes by watershed that were determined in the EIS based on stressors were then evaluated in light of the additional stressor of horizontal drilling in Marcellus shale. Viability outcomes by species, by watershed with the potential for drilling in the Marcellus shale formation and Forest Plan Alternatives are found in Table J2, Appendix J. Viability outcomes are:

Outcome A. Species is well distributed and abundant within watershed. Forest Service may influence conditions in the watershed to keep it well distributed. Likelihood of maintaining viability is high.

Outcome B. Species is potentially at risk in the watershed; however, the extent and location of NFS lands with respect to the species is conducive to positively influence the sustainability of the species within this watershed. Therefore, likelihood of maintaining viability is moderate.

Outcome C. Species is potentially at risk within the watershed; however, the extent and location of NFS lands with respect to the species is NOT conducive to positively influence the sustainability of the species within this watershed. Therefore, species viability in the watershed may be at risk.

Outcome D. The species is so rare within the watershed (population is at very low density and/or at only a few local sites) that stochastic events (accidents, weather events, etc.) may place persistence of the species within the watershed at risk; however, the extent and location of NFS lands with respect to the species is conducive to positively influence the sustainability of the species within this watershed. Therefore, likelihood of maintaining viability is moderate.

Outcome E. The species is so rare within the watershed (population is at very low density and/or at only a few local sites) that stochastic events (accidents, weather events, etc.) may place persistence of the species within the watershed at risk. Forest Service ability to positively influence the species is limited. Therefore species viability in the watershed may be at risk.

A summary of the changes by alternative is below.

Table 3D-15. Viability Outcomes by Alternative based on Marcellus Shale Potential Development

Viability Outcome	Number of Species/Watershed Combinations with the Specified Outcome								
	EIS viability outcome	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
A (Low Risk)	7	2	2	6	2	6	2	6	2
B (Moderate Risk, FS May Positively Influence)	30	10	10	20	10	20	10	20	15
C (Potential High Risk, Little Opportunity for FS Influence)	43	68	68	54	68	54	68	54	63
D (Moderate Risk, FS May Positively Influence)	22	17	17	21	17	21	17	21	18
E (Potential Very High Risk, Little Opportunity for FS Influence)	13	18	18	14	18	14	18	14	17

Changes to aquatic species viability based on the additional stressor of horizontal drilling in Marcellus shale were similar in Alternatives C, E, G and I because none of the alternatives allow horizontal drilling. The species viability changed from low or moderate risk to potential high or very high risk in those watersheds where the species occurrence was on Marcellus shale in National Forest, but with privately owned mineral rights.

Changes to aquatic species viability were similar in Alternatives A, B, D, and F because all of those alternatives allow horizontal drilling in Marcellus shale to some extent. The species viability changed from low or moderate risk to potential high or very high risk in those watersheds where the species occurrence was on Marcellus shale in National Forest. The exception was in the North Fork South Branch Potomac River watershed (includes the Laurel Fork area), where although the area is underlain by Marcellus shale in Federal ownership, oil and gas leasing of the area will not be allowed in all alternatives.

Changes to aquatic species viability in Alternative H were in between those of the two other alternative groupings described above. This is because Alternative H allows horizontal drilling in Marcellus shale but has restricted it in more areas than Alternatives A, B, D, and F.

Vegetation

The Reasonably Foreseeable Development (RFD) for federal oil and gas on the George Washington National Forest is related primarily to the Marcellus shale formation. Potential areas of development contain a full range of ecological systems as well as a range of site productivity depending upon the specific location of projected activities. Table 3D-16 indicates the level of clearing during the first 10 years of plan implementation as well as the projected volume of timber that would be removed for each alternative.

Table 3D-16. Acres Cleared and Associated Timber Removal Volumes for the Federal Leases

Alternative	Acres Cleared	Volume (CCF, Hundred Cubic Feet)
A	1,436	29,000
B	833	17,000
C and I	0	0
D	833	17,000
E	168	3,000
F	446	9,000
G	173	3,000
H	380	8,000

Assumption of average volume per acre cleared equals 20 CCFs.

As Table 3D-16 displays, Alternatives A, B, and D oil and gas leasing could result in substantially more acres of vegetation during the first 10 years of plan implementation. Alternatives E through H would result in comparatively less acres of vegetation cleared. However, in all cases less than 1% of the forested acres on the GWNF would be impacted. Many if not most of these acres would likely be removed from timber production for the foreseeable future. Alternatives C and I would result in no clearing. All vegetation would be removed from the acres cleared for well sites, access roads, and associated pipelines. Some revegetation or restoration of disturbed areas after completion of gas exploration may eventually result in similar vegetation being established on portions of the cleared area.

Fair market value for timber volume indicated in 3D-16 will be obtained through timber settlement sale or commercial timber sale regulations as individual site development occurs. Every effort will be made to make marketable timber available to local markets.

Special Biological Areas, Caves and Rare Communities

The Reasonably Foreseeable Development assumes that oil and gas activities will occur for the exploration and development of the Marcellus Shale, primarily on the Lee, North River, Warm Springs, and James River Ranger Districts. A number of rare communities, caves, and Special Biological Areas occur on the Forest and they act as a "coarse filter" for the protection of biological diversity. According to SAMAB (1996) about 66% of TES species are associated with rare communities, and the percentage increases even further when riparian areas are included. By protecting rare communities, including caves, a very large number of TES plant and animal species also receive protection. Added to this are Special Biological Areas where single occurrences or assemblages of TES species are recognized and protected.

The possible effects of oil and gas development on rare communities, caves, and Special Biological Areas include removal of tree species, ground disturbance, changes in hydrology, changes in soil temperature, and possible invasion by non-native species. Even though there may be activities associated with oil and gas development, the Plan Standards provide protection for threatened, endangered, and sensitive species that occur within rare communities, caves, and Special Biological Areas. The areas may receive some disturbance, but project and site-specific analysis will include mitigation to prevent damage to the integrity of these areas and the species that depend on them.

Forest Plan direction for rare communities, caves, and Special Biological Areas is to protect the natural resource values associated with them. They are generally not actively managed, except where necessary for their restoration and maintenance.

In Alternative H Special Biological Areas, Key Natural Heritage Community Areas, and the Shenandoah Crest are all only available under No Surface Occupancy. This will provide further protection for any rare species associated with these areas.

Management Indicator Species

Concerns regarding overall biodiversity of the areas proposed for federal oil and gas development are best addressed through the use of Management Indicator Species (MIS) as designated by the Forest Plan (Table 3B2-8). Wildlife resources on the Forest are located in Virginia and West Virginia and are managed in cooperation with the Virginia Department of Game and Inland Fisheries (VDGIF) and the West Virginia Division of Natural Resources (WVDNR). State wildlife agencies set policy for hunting and fishing regulations and associated law enforcement programs. The Forest Service manages the habitat conditions for wildlife. The following discussion focuses on the habitat conditions that support wildlife populations in the area.

Under the National Forest Management Act (NFMA) the Forest Service is charged with providing for a diversity of plant and animal communities consistent with overall multiple use objectives. Management Indicator Species (MIS) are a planning tool used to accomplish this requirement (36 CFR 219.19). They are selected during forest planning "because their population changes are believed to indicate the effects of management activities" (36 CFR 219.19(a)(1)) on important elements of plant and animal diversity.

The Reasonably Foreseeable Development (RFD) for federal oil and gas (particularly in the Marcellus shale) on the George Washington National Forest is concentrated on the Lee, North River, Warm Springs, and James River Ranger Districts.

Cow Knob Salamander. This salamander is a species with a restricted range. It is endemic to the higher elevations of Shenandoah Mountain along the VA/WV border. It is a terrestrial salamander that occurs primarily above 2,500 feet in elevation and mainly occurs in rocky talus areas on north to northeast aspects. It forages openly on cool to warm, dark, humid/rainy nights consuming small insects and other invertebrates. The Cow Knob salamander is an MIS because it is a Sensitive species and a narrow endemic that occurs almost entirely on the George Washington National Forest (North River Ranger District). The range of the Cow Knob salamander overlaps with the location of Marcellus shale on the Forest. Under an agreement with the U.S. Fish and Wildlife Service (1994) no road construction is permitted on the Forest within the Cow Knob conservation area. This would greatly inhibit gas well development. The agreement also states, that while the

conservation area is available for oil and gas leasing, controlled surface use stipulations will be used to protect the salamander's habitat and populations. These controlled surface use stipulations are subject to approval by the Cow Knob salamander Conservation Team. In Alternative H the Shenandoah Crest and the area south of Highway 250 on Shenandoah Mountain greater than 3,000 feet in elevation are only available with No Surface Occupancy.

Pileated Woodpecker. The Pileated Woodpecker generally prefers mature deciduous forests ranging from bottomlands to uplands. Key habitat requirements include older mature forests with dead trees (snags) for nesting. Pileated woodpeckers will also nest in large dead limbs on live trees. Nests are large cavities they construct usually over 30 feet above the ground. They feed on ants, insects, and insect larvae (mainly carpenter ants and wood-boring beetles) found by probing under the bark of standing trees and in stumps or fallen logs. Some fruits and berries are taken in fall and winter (Hamel 1992). These woodpeckers are year-round residents. The pileated woodpecker is an MIS for snag dependent wildlife.

Ovenbird. Preferring mature, dry, deciduous hardwoods with a closed canopy, the ovenbird is an area sensitive MIS requiring relatively large undisturbed tracts. As ground nesters, they are especially vulnerable to predators. Breeding habitat is deciduous or mixed forest (rarely pure pine woods) with moderate understory, preferably in uplands. Since the ovenbird is a neotropical migrant, arriving in spring and departing the Forest in the fall, declines in populations may be caused by events happening on the wintering areas, not the Forest.

Chestnut-sided Warbler. The habitat of this common warbler is typically second-growth hardwoods and overgrown fields in the Appalachian Mountains over 3,500 feet. On the Forest it's therefore found in the Blue Ridge, Ridge and Valley, and Cumberland mountains. It's most numerous in abandoned fields with scattered saplings, along woodland edges, and in open park-like deciduous woods. It nests 1 to 4 feet above the ground in saplings and shrubs and feeds on insects gleaned from leaves and twigs in deciduous vegetation (Hamel 1992). The chestnut-sided warbler is an MIS for high elevation early-successional habitats because of its strong association with these habitats, and because its populations should be responsive to forest management efforts that create and sustain such habitats. Also, the chestnut-sided warbler is effectively monitored using established breeding bird survey protocols. Since the chestnut-sided warbler is a neotropical migrant, arriving in spring and departing the Forest in the fall, declines in populations may be caused by events happening on the wintering areas, not the Forest.

Acadian Flycatcher. This common flycatcher is found mainly in moist deciduous forests with a moderate understory near streams. Nests are found on horizontal or down-hanging branches of deciduous trees, usually over a stream. This arboreal hawking insectivore generally sits on a branch 10 to 40 feet high near a stream where it will sally after flying insects (Hamel 1992). The Acadian flycatcher is deemed an appropriate species to indicate management-induced changes to mature riparian forests. It is highly associated with mature deciduous forests along streams and bottomland hardwoods throughout the Forest. This species is selected to help indicate the effects of management activities on mature riparian habitats. Since the Acadian flycatcher is a neotropical migrant, arriving in spring and departing the Forest in the fall, declines in populations may be caused by events happening on the wintering areas, not the Forest.

Eastern Towhee. Also called the Rufous-sided towhee, this widespread bird is found most commonly in upland brushy habitats, woodland margins, thickets, cut-over woods, and overgrown fields. Key habitat requirements are shrubs, saplings, and understory trees where a thicket is present. Nests are most often located in thickets and brushy places on the ground or in shrubs and saplings up to 5 feet off the ground. Towhees forage on the ground and in low shrubs where they scratch in leaf litter to expose insects, seeds, and fruits that they glean (Hamel 1992). Towhees are year-round residents although individuals will migrate short distances. The Eastern towhee was selected as an MIS to indicate the effects of management activities on early seral habitats.

Black Bear. The black bear is an opportunistic species that can thrive in a wide variety of habitats. The black bear's most important habitat need is considered to be freedom from constant human disturbance. Remote habitat free from the regular presence of humans is an important component of bear habitat quality. Access management does not refer to the prohibition of building or upgrading existing roads, but rather to their subsequent management after construction such as whether they're open or closed and the timing of closure. Roads in and of themselves are not detrimental; it's the use of these roads by the public that affects black

bear. At least five percent of the area should be in an age class of older trees and these should be well dispersed over the area. Mature forests with large diameter trees are needed to provide hard mast and hollow den trees.

Eastern Wild Turkey. Wild turkeys prefer mature forests (mid- to late successional) with open understories, temporary and permanent clearings well dispersed, and freedom from disturbance during nesting and brood rearing seasons. The key components of wild turkey habitat in oak-hickory forests are brood habitat, nesting and fall/winter habitat, and freedom from disturbance. Brood habitat is the most limiting factor to eastern turkey population in the central Appalachians (Pack, personnel communication). Hens with broods use a wide variety of habitats. These include pastures with hay fields, utility rights-of-way, wildlife clearings, burned areas, and natural glades or savannas; however, the structure of vegetation is as important as vegetation types (Healy 1981). In mature forests, ideal brood habitat includes at least 5% of the area in well-dispersed, permanent grass/herbaceous openings. Ground cover should consist of patchy vegetation that does not impede poult movements, yet provides good horizontal cover from predators, and produces abundant insects for food. Partially canopied (<60%) savannahs that are open and park-like with moderate herbaceous/shrubby understory with little midstory vegetation provide optimal brood habitat. Nesting and fall/winter habitat may include uncut hay fields, areas harvested for timber, and burned forests. Nesting habitat should be near brood habitat. Preferred and most successful nest sites seem to be on the edge of extensive stands of brush and herbaceous vegetation. Hard mast (usually acorns) is the most important fall food of the eastern turkey in the central Appalachians. Because of the variation in mast production between oak groups, a variety of oak species best provides sustained mast production. Ideal habitat includes at least 60% of the area in mast bearing age (50 years+). Human disturbance to hens and broods during the nesting and brood rearing season should be minimized. No more than one mile of open road per 1,000 acres will minimize this disturbance.

White-Tailed Deer. White-tailed deer use a variety of habitat types. White-tailed deer prefer early successional forest areas, woodland edge, and a mosaic of various forest age classes. A mixture of habitat types and resulting edge insures an abundant food source is available throughout the year. White-tailed deer heavily use hard mast in the fall (usually acorns) to accumulate sustaining fat reserves for the winter. During the winter woody browse makes up the majority of a deer's diet in the central Appalachians. In the spring and summer they consume young growing herbaceous plants, fruits, and woody shoots and leaves. Early successional habitat, generally no larger than 25 acres in size, well dispersed with approximately 10% of the area in the 0-10 age class provides forage and escape cover throughout the year. Well-dispersed forest openings 1/2 to 1 acre in size occupying up to 5% of the area and shrub-grass habitats provide necessary spring/summer foods. In extensive forested areas a minimum of 60% of the area maintained in mast bearing age (40 years +) provides suitable fall hard and soft mast for white-tailed deer.

Hooded Warbler. Habitat of this common warbler is moist deciduous and mixed forests with a dense understory, typically found in rich woods, ravines, and bottomlands. Key habitat requirements are forests (usually deciduous) with a thick, rich understory layer. The hooded warbler is rarely associated with moist deciduous forests above 4,000 feet (Hamel 1992). Nests are built 2 to 5 feet above the ground in shrubs and saplings where they are poorly concealed. These warblers forage primarily in shrubs within 15 feet of the ground by gleaning and hawking insect prey. The hooded warbler is an MIS for mid- to late-successional oak and oak-pine forests. Since the hooded warbler is a neotropical migrant, arriving in spring and departing the Forest in the fall, declines in populations may be caused by events happening on the wintering areas south of the U.S. and not on the Forest.

Scarlet Tanager. This common woodland bird is typically found in upland mature deciduous (usually oak) forests for which it was selected as an MIS. It's most common in lower and middle elevations in the mountains up to 4,000 feet and is rarely found over 5,000 feet. The key habitat feature is mature deciduous forests. Nests are located 20 to 50 feet above the ground in a hardwood tree. The scarlet tanager feeds on insects that it gleans from twigs and leaves (Hamel 1992). In the fall it often will feed on berries. Since the scarlet tanager is a neotropical migrant, arriving in spring and departing in the fall, declines in populations may be caused by events happening on the wintering areas south of the U.S. and not on the Forest.

Pine Warbler. The pine warbler is closely associated with middle-aged to mature pine and pine-oak forests, generally occurring only where some pine component is present. While not among the common warblers, it is

considered the most appropriate MIS for the yellow pine habitat component. Nests are built in pines and foraging for insects occurs in the crowns of pines where they glean insects from needles and twigs (Hamel 1992). Since the pine warbler is a neotropical migrant, arriving in spring and departing the Forest in the fall, declines in populations may be caused by events happening on the wintering areas south of the U.S. and not on the Forest.

Wild Brook Trout. These trout are cold-water species that require water temperature less than 69 degrees Fahrenheit, dissolved oxygen values greater than 7.0 parts per million, and sedimentation rates that are in equilibrium with the watershed. To be considered "wild" they must be a reproducing population that is not dependent on stocking. Positive activities within watersheds that support wild trout are those that stabilize or improve the physical and biological conditions of the stream. For a complete discussion of effects on wild trout as an MIS in relation to this project see "*Aquatic Viability Determinations for Oil and Gas Leasing.*"

Beaver. Beavers were selected as an MIS because they are a keystone species that create wetland habitat with many physical and biological benefits. Beavers alter ecosystem hydrology, biogeochemistry, vegetation, and productivity with consequent positive effects on the plant, vertebrate, and invertebrate populations that occupy beaver-modified landscapes. Their impoundments trap fine textured sediments that act as water storage reservoirs, resulting in slow, sustained discharge that maintains streamflows during dry periods; afford protection from flooding of downstream areas; and produce a raised water table that enhances riparian zones. Additionally, beaver habitat modifications can reduce pollution and improve water quality in aquatic ecosystems, by trapping sediment and nutrients; reducing downstream turbidity; and purifying water from acidification and other non-point source pollutants. The capability of beavers to store water, trap sediment, reduce erosion, and enhance riparian vegetation can be used as a management tool to restore degraded aquatic and riparian ecosystems. Beavers are a habitat-modifying species and play a pivotal role in influencing community structure in many riparian and wetland systems. Restoring beaver populations to their maximum viability on public lands is desirable because of the beaver's capability to restore and maintain healthy riparian ecosystems. Key conservation elements for the beaver on National Forest System lands are, therefore, protection and enhancement of aquatic and riparian habitats by management of water resources and riparian vegetation, beaver population enhancement by natural recolonization and transplants where necessary, and proactive management of beaver damage issues.

The physical effects of oil and gas leasing upon wildlife include elimination of individual animals and their associated habitat by construction or reconstruction of access roads, clearing and leveling of drill pad sites, and construction of pipelines and off-site facilities, and reduction of availability and quality of water and wetland habitat (see aquatic viability determinations for oil and gas leasing). There is no anticipated gas well development in the next two decades on the Pedlar Ranger District. The potential impacts from new gas well development on the Lee, North River, Warm Springs, and James River Ranger Districts would vary by alternative.

Forest fragmentation can affect wildlife by encouraging species that use early successional and forest edge habitats, such as the MIS eastern towhee and wild turkey, and discouraging animals that use interior forest habitats, such as the ovenbird and hooded warbler. Under all alternatives, road, pipeline, facility, and drill pad construction would reduce existing mature forest habitat and increase the amount of edge in the project area. However, these hard mast/mature forest/old age forest habitat conditions will remain well connected over the 15-year period and forested travel corridors free from constant disturbance are maintained by road access closure. Forest fragmentation would be minimal given the narrow clearing widths for roads and pipelines and the small acreage disturbed when compared to the extensive surrounding unfragmented forests. Given the Lee, North River, Warm Springs, and James River Ranger Districts are in a generally forested landscape, the expected negative impacts of edge are not considered significant.

Early seral habitat would be increased in all alternatives where roads and/or well pads are not allowed to redevelop into forest conditions. The increase in grass/forbs under all alternatives would provide food source for such MIS as whitetail deer, wild turkey, and indirectly for such species as the eastern towhee. While hard mast is reduced under all alternatives due to reduction of forested acres, hard mast production capability is still retained on adjacent acreage. It is likely that soft mast production (fruits and berries) will increase under all alternatives with plants such as blackberry, raspberry, and pokeweed occurring where land is cleared.

Under all alternatives, road use during active drilling and post-drilling and production phases would include heavy truck traffic and during active drilling, round the clock truck use bringing water onto the site and taking used fluids away from the drilling pads. Noise impacts around the drilling sites and truck use of roads leading to drilling pads could impact wildlife, causing movement away from the drilling areas. While vegetation around roads and drilling pads may enhance habitat for some species of public interest such as white-tailed deer, black bear and wild turkey, hunting opportunities in these areas could be limited, due to the larger volume of traffic and noise during active drilling and production phases.

Numbers of snags will be reduced in all alternatives due to the number of acres of forest that will be cleared. Snag development generally takes 80 to 100+ years; therefore, even if cleared land is allowed to return to forest, it will take many decades for snags to develop once trees achieve a mature size and then die. However it is likely this loss of snags will be offset over time by increased tree mortality resulting from insect infestations such as gypsy moth and pine bark beetles.

In those Alternatives where horizontal drilling is allowed (A, B, D, F, and H), development activities would be controlled in riparian areas through lease stipulations or conditions of approval on plans of operation. However, impacts from water withdrawal and/or non-point source pollution on wetland and riparian habitat could have impacts on riparian MIS such as Acadian flycatcher, pileated woodpecker, beaver, and brook trout (see "*Aquatic Viability Determinations for Oil and Gas Leasing*").

A summary of expected effects to MIS are shown in Table 3D-17 below.

Table 3D-17. Expected Effects to Management Indicator Species by Alternative

Common Name	Management Effects Indicated	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Cow Knob Salamander	TES species dependent on mature, moist hardwood forest	=/=	=/=	=/=	=/=	=/=	=/=	=/=	=/=
Pileated Woodpecker	Snag-dependent wildlife species	=/-	=/-	=/-	=/-	=/-	=/-	=/-	=/-
Ovenbird	Mature forest interior species	=/-	=/-	=/-	=/-	=/-	=/-	=/-	=/-
Chestnut-sided Warbler	High-elevation early successional species	=/=	=/=	=/=	=/=	=/=	=/=	=/=	=/=
Acadian Flycatcher	Mature riparian forest dependent species	=/=	=/=	=/=	=/=	=/=	=/=	=/=	=/=
Hooded Warbler	Mid- and late successional deciduous forest species, inc. mixed mesophytic, oak & oak-pine forests	=/-	=/-	=/-	=/-	=/-	=/-	=/-	=/-
Eastern Towhee	Early seral habitat	=/+	=/+	=/+	=/+	=/+	=/+	=/+	=/+
Scarlet Tanager	Upland oak forest species	=/-	=/-	=/-	=/-	=/-	=/-	=/-	=/-
Pine Warbler	Mid- and late successional pine and pine-oak forests	=/-	=/-	=/-	=/-	=/-	=/-	=/-	=/-
Deer	Meeting hunting demand for this species	=/+	=/+	=/+	=/+	=/+	=/+	=/+	=/+
Beaver	Keystone wetland species	=/-	=/-	=/=	=/-	=/=	=/-	=/=	=/-
Eastern Wild Turkey	Meeting hunting demand for this species	=/+	=/+	=/+	=/+	=/+	=/+	=/+	=/+
Black Bear	Meeting hunting demand for this species	=/=	=/=	=/=	=/=	=/=	=/=	=/=	=/=
Wild Brook Trout	Meeting angling demand for this species	=/--	=/--	=/=	=/--	=/=	=/--	=/=	=/-

Population trend expressed as expected change from current levels following implementation of proposed action: "++" relatively large increase, "+" increase, "=" little to no change, "-"decrease, "- -" relatively large decrease.

Threatened, Endangered and Sensitive (TES) Species

The majority of the Reasonably Foreseeable Development for oil and gas will occur on the Lee, North River, Warm Springs, and James River Ranger Districts which provide habitat for 7 federally threatened and endangered terrestrial species, which include 3 plants, 3 mammals and one mussel. Two federally listed species, Virginia sneezeweed and swamp pink occur only on the Pedlar Ranger District where there is no Marcellus Shale and, therefore, are not considered further. There are no known occurrences of the Madison Cave isopod on the GNWF, but about 700 acres of potential habitat have been modeled on the Forest. There are 70 terrestrial species designated by the Regional Forester as sensitive on the Lee, North River, Warm Springs, and James River Ranger Districts. Sensitive species include species occurring on the Forest with range-wide viability concerns, but which are not included on lists of endangered, threatened, proposed, or candidate species. Sensitive species receive special management emphasis in order to ensure their viability and to preclude trends toward federal listing or endangerment. Forest terrestrial threatened, endangered, and sensitive species that might be affected by the oil and gas leases occur in two ecological sections: the Northern Ridge and Valley, and the Allegheny Front. Each of these sections contains distinct geologies and landforms, which give rise to a variety of unique habitats such as boreal forests, caves, wetlands, shale barrens, fire-adapted communities, glades, sinkholes, and springs. These unique habitats, in turn, support assemblages of rare plant and animal species. In addition to the habitat diversity found in the ecological sections, the Forest encompasses a wide range of latitude. Many plant and animal species more typically associated with northern or southern biomes reach the limit of their range on the Forest. For the oil and gas leasing analysis, species that could potentially be affected are shown below:

Table 3D-18. TES Species Potentially Affected by Oil and Gas Leasing on the GWNF

Species Name	Common Name	Range on or near GWJNFs	Habitat - Detail	TES	G Rank	VA SRank	WV SRank
VERTEBRATES							
Fish							
Notropis semperasper	Roughhead shiner	Upper James R watershed above Buchanan	Aquatic-rivers	S	G2G3	S2S3	-
Noturus gilberti	Orangefin madtom	S Fk Roanoke R watershed, Roanoke R above Salem, Craig Ck, Johns Ck, Cowpasture R	Aquatic-streams	S	G2	S2	-
Amphibian							
Plethodon punctatus	Cow Knob salamander	Shenandoah Mtn, VA & WV	Mixed oak, late successional with loose rocks and logs, >2500'	S	G3	S2	S1
Birds							
Falco peregrinus	Peregrine Falcon	Hack sites late 80s & early 90s No nests, current migrant.	Nests on ledges or cliffs, buildings, bridges, quarry walls. Non-breeding sites, farmland, open country, lakeshores, broad river valleys, airports	S	G4	S1B/S2N	S1B/S2N
Haliaeetus leucocephalus	Bald Eagle	Potomac R, James R watershed	Feeds and nests on or near large lakes and rivers	S	G5	S2S3B/S3N	S2B/S3N
Lanius ludovicianus migrans	Migrant Loggerhead Shrike	Ridge & Valley (Shenandoah Valley)	Open grasslands with trees and shrubs, fencerows	S	G4	S2B/S3N	S1B/S2N
Thryomanes bewickii altus	Appalachian Bewick's wren	Historical records in Botetourt, Giles, Highland, Washington Cos	Thickets, old fields, fencerows, old home sites	S	G5T2Q	S1B/SZN	S1B/S1N

Species Name	Common Name	Range on or near GWJNFs	Habitat - Detail	TES	G Rank	VA SRank	WV SRank
Mammals							
Corynorhinus townsendii virginianus	Virginia big-eared bat	Summer: VA - Highland Co. (1 cave), WV - Pendleton Co. (4 caves); Winter: Highland, Rockingham, Pendleton Co. (6 caves), largest WV population in Pendleton Co. Small #'s of bats (usually <10) in a few other widely scattered caves during summer months. Bath & Pulaski County records are historic, no occupied caves currently known.	Resides in caves winter and summer. Short distance migrant (<40 miles) between winter and summer caves. Forages primarily on moths and foraging habitat is common (fields, forests, meadows, etc.). Forages within 6 miles of summer caves. USFWS Critical Habitat is 5 caves in WV (4 Pendleton Co. & 1 Tucker Co.). Closest Critical Habitat cave to GWJNF is ~3 miles in Pendleton Co., WV.	E	G4T2	S1	S2
Glaucomys sabrinus fuscus	Virginia northern flying squirrel	Laurel Fork area, Highland Co	Spruce-fir forests and adjacent northern hardwoods	E	G5T2	S1	S2
Microtus chrotorrhinus carolinensis	Southern rock vole	Alleghany Mtn, Bath Co	Cool, moist, mossy talus under oaks/northern hardwoods	S	G4T3	S1	S2
Myotis leibii	Eastern small-footed bat	Ridge & Valley	Hibernates in caves during winter, roosts in crevices of large rock outcrops, cliffs, & under large rocks in talus & boulder-fields during summer, forages widely in all forested and open habitat types over both ridges and valleys.	S	G3	S1	S1
Myotis sodalis	Indiana bat	Blue Ridge, Ridge & Valley, Cumberland Mtns	Caves winter, upland hardwoods summer, forages widely along riparian areas and open woodlands	E	G2	S1	S1
Sorex palustris punctulatus	Southern water shrew	Alleghany Mtn, Bath Co; & Laurel Fork, Highland Co	Riparian areas w/in spruce-fir forests and northern hardwoods	S	G5T3	S1S2	S1
INVERTEBRATES							
Snail (Mollusk, Class Gastropoda)							
Glyphyalinia raderi	Maryland glyph	Alleghany, Montgomery Cos	Calciphile, edge of seeps within leaf litter	S	G2	S1S2	S2
Helicodiscus diadema	Shaggy coil	Alleghany Co	Calciphile, limestone rubble and talus	S	G1	S1	-
Helicodiscus lirellus	Rubble coil	Rockbridge Co	Calciphile, limestone rubble and talus	S	G1	S1	-
Helicodiscus triodus	Talus coil	Alleghany, Botetourt, Rockbridge Cos	Calciphile, limestone rubble on wooded hillsides and caves	S	G2	S1S2	SH
Clam and Mussel (Mollusk, Class Bivalvia)							
Alasmidonta varicosa	Brook floater	Potomac drainage	Aquatic-rivers	S	G3	S1	S1
Elliptio lanceolata	Yellow lance	Roanoke R, James R	Aquatic-rivers	S	G2G3	S2S3	-
Lasmigona subviridis	Green floater	Widely distributed in N & S Fk Shenandoah R, Pedlar R, James R	Aquatic-rivers	S	G3	S2	S2
Pleurobema collina	James spinymussel	Potts Ck, Craig Ck, Johns Ck, Patterson Run, Pedlar R, Cowpasture R, Mill Ck (Deerfield)	Aquatic-rivers	E	G1	S1	S1

Species Name	Common Name	Range on or near GWJNFs	Habitat - Detail	TES	G Rank	VA SRank	WV SRank
Amphipod (Crustacean, Order Amphipoda)							
Stygobromus gracilipes	Shenandoah Valley cave amphipod	Frederick, Rockingham, Shenandoah, Warren Cos	Caves	S	G3G4	S2S3	S1
Stygobromus hoffmani	Alleghany County cave amphipod	Low Moor cave, Alleghany Co	Caves	S	G1	S1	-
Stygobromus mundus	Bath County cave amphipod	Alleghany, Bath Cos	Caves	S	G2G3	S1S2	-
Isopod (Crustacean, Order Isopoda)							
Miktoniscus racovitzai	Racovitza's terrestrial cave isopod	Alleghany, Botetourt, Page, Rockbridge, Shenandoah Cos	Caves	S	G3G4	S2	-
Antrolana lira	Madison Cave Isopod	Augusta, Rockingham, Warren and Clarke Cos	Caves	T	G2G4	S2	S1
Millipede (Class Diplopoda)							
Nannaria shenandoah	Shenandoah Mountain Xystodesmid millipede	One site: along Long Run Road, Rockingham Co	Leaf litter, mixed oak forest	S	G1	S1	-
Pseudotremia alecto	a millipede	Griffith Knob, Alleghany Co; near Mountain Grove Saltpetre cave, Bath Co	Leaf litter, deciduous forests	S	G1	S1	-
Centipede (Insect, Order Chilopoda)							
Nampabius turbator	a cave centipede	One known site: Low Moor cave, Alleghany Co	Caves	S	G1G2	S1	-
Springtail (Insect, Order Collembola)							
Arrhopalites carolynae	A cave springtail	Augusta, Highland, Bath, Lee, Wise Cos	Caves	S	G2G4	S1	-
Arrhopalites sacer	A cave springtail	Bath Co	Caves	S	G1G2	S1	-
Dragonfly and Damselfly (Insect, Order Odonata)							
Gomphus viridifrons	Green-faced clubtail	New R, Craig Ck, Pound R, Locust Spring	Aquatic-rivers	S	G3	S2	S2
Beetle (Insect, Order Cloeoptera)							
Cicindela ancocisconensis	Appalachian tiger beetle	Alleghany, Bath, Highland, Lee, Rockbridge, Washington, Wise Cos	Riparian – sandy/silty edges of streams and rivers	S	G3	S2	S3
Cicindela patruela	Northern barrens tiger beetle	Blue Ridge, Ridge & Valley	Eroded slopes of exposed sandstone and conglomerate	S	G3	S2	S2S3
Hydraena maureenae	Maureen's shale stream beetle	Alleghany, Bath, Botetourt, Bland, Craig, Cos	Interstitial water in riparian-shale substrate along stream edge	S	G1G3	S1S3	-
Butterfly and Moth (Insect, Order Lepidoptera)							
Callophrys irus	Frosted elfin	Frederick, Montgomery, Page, Roanoke Cos	Dry, open woods, clearings, and road/powerline ROWs w/ abundant wild indigo (*Baptisia tinctoria*)	S	G3	S2?	S1

Species Name	Common Name	Range on or near GWJNFs	Habitat - Detail	TES	G Rank	VA SRank	WV SRank
Erynnis persius persius	Persius duskywing	Blue Ridge, Ridge & Valley	Bogs, wet meadows, open seepages in boreal forests	S	G5T1T3	S1	-
Pyrgus centaureae wyandot	Appalachian grizzled skipper	Ridge & Valley	Shale barrens, open shaley oak woodlands	S	G5T1T2	S1S2	S1
Speyeria diana	Diana fritillary	Blue Ridge, Ridge & Valley	Grasslands-shrublands, near streams with thistles and milkweeds, larval host plant, violets	S	G3G4	S3	S2S3
Speyeria idalia idalia	Regal fritillary	Blue Ridge, Ridge & Valley	Riparian, grasslands-shrublands	S	G3T1Q	S1	S1
Catocala herodias gerhardi	Herodias underwing	Bald Knob, Bath; Poverty Hollow, Montgomery Co; Sand Mtn, Wythe Co (non FS property)	Pitch pine/bear oak scrub woodlands, >3000'	S	G3T3	S2S3	SU
Erythroecia hebardi	Hebard's noctuid moth	Bath Co	Rich, mesic hardwood forest. Larvae host plant is Canada horse-balm (*Collinsonia canadensis*).	S	GU	SH	-
Euchlaena milnei	Milne's euchlaena moth	Edinburg Gap, Shenandoah Co	Moist, forested slopes of mixed pine hardwoods. Acidic oak woods.	S	G2G4	S2	S2
NON-VASCULAR PLANTS							
Lichen							
Hydrothyria venosa	Waterfan	Amherst, Alleghany, Bedford, Botetourt, Giles, Madison, Nelson, Rockbridge, Shenandoah Cos	Aquatic – in streams/springs/cascades	S	G3G5	S1	-
Liverwort							
Nardia lescurii	a liverwort	Blue Ridge, Ridge & Valley	Riparian – on peaty soil over rocks, usually in shade and associated w/ water, <3000'	S	G3?	SU	-
VASCULAR PLANTS							
Aconitum reclinatum	Trailing white monkshood	Blue Ridge, Ridge & Valley	Rich cove sites, streambanks, seepages all with high pH	S	G3	S3	S3
Allium oxyphilum	Nodding onion	Monroe, Summers, Mercer, Greenbrier Cos, WV	Shale barrens, sandstone glades	S	G2Q	-	S2
Arabis patens	Spreading rockcress	Frederick, Lee, Page, Shenandoah, Warren Cos	Shaded, calcareous cliffs, bluffs, and talus slopes	S	G3	S2	S2
Arabis serotina	Shale barren rockcress	Ridge & Valley N of New R watershed	Shale barrens and adjacent open oak woods	E	G2	S2	S2
Berberis canadensis	American barberry	Blue Ridge, Ridge & Valley	Calcareous open woods, bluffs, cliffs, and along fencerows	S	G3	S3S4	S1
Buckleya distichophylla	Piratebush	Blue Ridge S of Roanoke R, Ridge & Valley S of James R	Open oak and hemlock woods	S	G2	S2	-
Carex polymorpha	Variable sedge	Blue Ridge, Ridge & Valley, N of James R	Open acid soil, oak-heath woodlands, responds to fire	S	G3	S2	S1
Carex schweinitzii	Schweinitz's sedge	Bath, Montgomery, Pulaski, Washington Cos	Bogs, limestone fens, marl marshes	S	G3G4	S1	-
Clematis coactilis	Virginia white-haired leatherflower	Ridge & Valley, Rockbridge Co, S to Wythe Co	Shale barrens, rocky calcareous woodlands	S	G3	S3	-

Species Name	Common Name	Range on or near GWJNFs	Habitat - Detail	TES	G Rank	VA SRank	WV SRank
Corallorhiza bentleyi	Bentley's coralroot	Alleghany, Bath, Giles Cos VA; Monroe, Pocahontas Cos WV	Dry, acid woods, along roadsides, well-shaded trails	S	G1G2	S1	S1
Delphinium exaltatum	Tall larkspur	Blue Ridge, Ridge & Valley	Dry calcareous soil in open grassy glades or thin woodlands	S	G3	S3	S2
Echinacea laevigata	Smooth coneflower	Alleghany, Montgomery Cos	Open woodlands and glades over limestone or dolomite	E	G2G3	S2	-
Euphorbia purpurea	Glade spurge	Blue Ridge, Ridge & Valley	Rich, swampy woods, seeps and thickets	S	G3	S2	S2
Heuchera alba	White alumroot	Shenandoah Mtn	High elevation rocky woods and bluffs	S	G2Q	S2?	S2
Hypericum mitchellianum	Blue Ridge St. John's-wort	Blue Ridge, Ridge & Valley	Grassy balds, forest seepages, moderate to high elevations	S	G3	S3	S1
Iliamna remota	Kankakee globe-mallow	Alleghany, Botetourt, Rockbridge, Bedford Cos	Open, disturbed riverbanks and roadsides	S	G1Q	S1	-
Juglans cinerea	Butternut	Blue Ridge, Ridge & Valley	Well-drained bottomland and floodplain, rich mesophytic forests mostly along toeslopes	S	G4	S3?	S3
Liatris helleri	Turgid Gayfeather	Blue Ridge, Ridge & Valley	Shale barrens, mountain hillside openings	S	G3	S3	S2
Lycopodiella margueritae	Marguerite's clubmoss	Bath Co	Seasonally moist soils, wet acidic ditches, borrow pits	S	G2	NA	-
Monotropsis odorata	Sweet pinesap	Blue Ridge, Ridge & Valley	Dry oak-pine-heath woodlands, soil usually sandy	S	G3	S3	S1
Paxistima canbyi	Canby's mountain lover	Ridge & Valley	Calcareous cliffs and bluffs, usually undercut by stream	S	G2	S2	S2
Phlox buckleyi	Sword-leaf phlox	Blue Ridge, Ridge & Valley	Open, often dry oak woodlands and rocky slopes, usually over shale in humus rich soils, often along roadsides	S	G2	S2	S2
Poa paludigena	Bog bluegrass	Blue Ridge, Ridge & Valley	Shrub swamps and seeps, usually under shade	S	G3	S2	S1
Potamogeton hillii	Hill's pondweed	Bath Co	Clear, cold calcareous ponds	S	G3	S1	-
Potamogeton tennesseensis	Tennessee pondweed	Ridge & Valley	Ponds, back water of streams and rivers	S	G2	S1	S2
Pycnanthemum torrei	Torrey's mountain-mint	Bland, Bath, Giles, Rockbridge, Wythe Cos	Open, dry rocky woods, roadsides, and thickets near streams, heavy clay soil over calcareous rock	S	G2	S2?	S1
Scirpus ancistrochaetus	Northeastern bulrush	Ridge & Valley	Mountain ponds, sinkhole ponds in Shenandoah Valley.	E	G3	S2	S1
Scutellaria saxatilis	Rock skullcap	Blue Ridge, Ridge & Valley	Rich, dry to mesic ridgetop woods, 32 counties in VA, likely G4/S4	S	G3	S3	S2
Sida hermaphrodita	Virginia mallow	Ridge & Valley, James R watersheds	Riverbank glades with loose rock or sandy soil	S	G3	S1	S3
Trillium pusillum var. moniticulum	Mountain least trillium	Great North Mtn & Shenandoah Mtn, VA & WV	Open oak woodlands in well-drained soil and margins of thickets	S	G3T2	S2	S1
Vitis rupestris	Sand grape	Ridge & Valley	Scoured banks of rivers and streams over calcareous bedrock	S	G3	S1?	S2

P=potentially affect by oil and gas leasing, E=endangered, T=threatened, S=sensitive

Federally Listed Species

Following is a brief description of each of the federally listed plant and animal species currently known to exist on the Lee, North River, Warm Springs, and James River Ranger Districts along with current management strategies for recovery.

Table 3D-19. Federally Threatened and Endangered Species for the GWNF

Taxa	Species	Status
Mammal	Indiana Bat (*Myotis sodalis*)	Endangered
Mammal	Virginia Big-Eared Bat *(Corynorhinus townsendii virginianus)*	Endangered
Mammal	Virginia Northern Flying Squirrel *(Glaucomys sabrinus fuscus)*	Endangered
Mussel	James Spinymussel (*Pleurobema collina*)	Endangered
Arthropod	Madison Cave Isopod *(Antrolana lira)*	Threatened
Vascular Plant	Shale Barren Rock Cress (*Arabis serotina*)	Endangered
Vascular Plant	Smooth Cone Flower (*Echinacea laevigata*)	Endangered
Vascular Plant	Virginia Sneezeweed (*Helenium virginicum*)	Threatened
Vascular Plant	Swamp Pink (*Helonius bullata*)	Threatened
Vascular Plant	Northeastern Bulrush (*Scirpus ancistrochaetus*)	Endangered

All of the known locations of the five listed plants and northern flying squirrel are in Special Biological Areas. The Laurel Fork Area, which has all currently known populations of northern flying squirrel, is unavailable for leasing under all alternatives. Virginia sneezeweed, swamp pink and northeastern bulrush are also confined to riparian areas. Riparian areas and Special Biological Areas have standards that should protect them from direct activities of gas drilling. In addition, Alternative H makes all Special Biological Areas as available only under No Surface Occupancy.

Indiana bat (*Myotis sodalis*). The distribution of Indiana bats is generally associated with limestone caves in the eastern U.S. (Menzel et al. 2001). Within this range, the bats occupy two distinct types of habitat. During summer months, maternity colonies of more than 100 adult females roost under sloughing bark of dead and partially-dead trees of many species, often in forested settings (Callahan et al. 1997). Reproductive females may require multiple alternate roost trees to fulfill summer habitat needs. Adults forage on winged insects within three miles of the occupied maternity roost. Swarming of both males and females and subsequent mating activity occurs at cave entrances prior to hibernation (MacGregor et al. 1999). During this autumn period, bats roost under sloughing bark and in cracks of dead, partially-dead and live trees. Wintering colonies occupy very specific climatic regimes in cool, humid caves or mines primarily west of the Appalachian Mountains (Barbour and Davis 1969; Menzel et al. 2001). Few sites provide these conditions, and approximately 85% of the species inhabits only nine caves or mine shafts (Menzel et al. 2001; USDI FWS 1999).

Although most hibernacula have been protected, the Indiana bat still appears to continue a 5% decline in range-wide population every two years (Cochran et al. 2000). Causes of decline are not known and have continued despite efforts to protect all known major hibernacula. Researchers are focusing studies on land use practices in summer habitat, heavy metals, pesticides and genetic variability in attempts to find causes for the declines.

Recommended habitat management includes protecting known significant hibernacula from human impacts, retaining forested condition around the entrances to significant hibernacula, and evaluating opportunities to protect Indiana bats through land acquisition (Menzel et al. 2001).

It is difficult to quantify summer roosting habitat for Indiana bat at a range-wide, regional or local level due to the variability of known roost sites and lack of knowledge about landscape scale habitat characteristics. Forest management practices that affect occupied roost trees may have local impacts on Indiana bat populations. However, the bats live in highly altered landscapes, depend on an ephemeral resource--dead and dying trees--and may be very adaptable. Anecdotal evidence suggests that these bats may respond positively to some degree of habitat disturbance (USDI FWS 1999).

Several caves on the Forest have been known to support Indiana bats, at least historically. Steps have been taken by the Forest to protect these caves for the Indiana bat. Both males and females hibernate in large caves and mine tunnels. In 1995, bat gates were installed in several caves on the Forest. These caves are Shire's Saltpetre Cave on the New Castle Ranger District, and Kelly Cave and Cave Springs Cave on the Clinch Ranger District. Shire's Saltpetre Cave and Kelly Cave are the only caves on the Forest known to have been hibernacula for Indiana bats, at least historically. Cave Springs Cave is not currently known to be a hibernaculum for any rare bat species, but it has the potential to serve as a hibernaculum. In addition, Cave Springs Cave is known to contain a variety of troglobitic amphipods and isopods. Both forest-wide standards and a specific management prescription surrounding Indiana bat hibernacula are designed to protect roosting and foraging habitat as well as the hibernacula for the Indiana bat. The primary cave protection area is administratively unavailable for Federal oil and gas leasing. The secondary cave protection area is available for leasing with controlled surface use stipulations to protect Indiana bat habitat.

Potential impacts from gas drilling (including horizontal drilling and hydraulic fracturing) that could result from the decision to make lands available for leasing could include direct impacts to the hibernacula and impacts to foraging and roost trees from surface clearing operations. The hibernacula are protected since the Indiana Bat Primary Cave Protection Areas are unavailable for leasing. The Indiana Bat Secondary Cave Protection Areas are available only with Timing restrictions in alternatives A through G and with No Surface Occupancy stipulations in Alternative H. Most of the underground cave system would be under the primary protection area, and all would be under the secondary protection area, so it is very unlikely that the main borehole in any drilling would go through the cave system. However, this would be evaluated in the environmental analysis accompanying any site specific Application for Permit to Drill. In regard to effects to the cave from the horizontal drilling, the primary cave protection areas would not have any horizontal drilling underneath them. The secondary cave protection areas, while not allowing surface occupancy, would allow the use of horizontal drilling underneath them. It is unlikely that the horizontal drilling would directly affect any caverns above the drilling. The deepest cave in the area surrounding the GWNF is about 800 feet deep. The depth of drilling expected to develop gas resources in the area is estimated to be 1,000 feet to 8,000 feet. Any potential impacts to cave systems from drilling would be fully evaluated in the environmental analysis accompanying any site specific Application for Permit to Drill.

Potential impacts on foraging activities and roost trees from the clearing of well pads and pipelines would be addressed in the review of Applications for Permit to Drill when the site specific nature of these impacts can be best analyzed. Concerns about bats utilizing water from open impoundments with hydraulic fracturing fluids would be addressed in Alternative H by the standard requiring closed loop systems for those fluids.

Virginia big-eared bat (Corynorhinus townsendii virginianus). This bat has a very limited range in Virginia and on the Forest. It uses caves as both hibernation and maternity sites and none of the caves known to be currently used in Virginia or West Virginia are on the GWJNF. This bat is also called the Western big-eared bat and formerly was in the genus *Plecotus* (you may still see it referred to this way). This species is listed as

endangered both at the federal (1979) and state (Virginia, 1987) level, and as of July 1, 2005 it is officially the Virginia state bat. This bat is unique in that it is one of two bats in Virginia that uses caves almost exclusively during both summer and fall (the other species with a similar life history is the gray bat - Myotis griscesens). In Virginia this bat is currently only known to occur in Tazewell County (3 caves) during the summer and 5 caves in three counties (Tazewell, Bland, & Highland) during the winter. There are historic records in Rockingham, Bath, and Pulaski Counties. The area in Virginia where this bat is concentrated, and of greatest concern, is in the Tazewell County area where there are relatively large (~1,500 to 2,000 individuals) and well known winter hibernacula and a summer maternity caves. Elsewhere in Virginia the bat is/was known to occur in caves with just a few individuals (usually <10), probably as transients. The Virginia big-eared bat forages almost exclusively on moths and will feed over a wide variety of habitats including hay fields, corn fields, meadows, forests, etc. - wherever moths are found. Therefore, caves (and only a very few) are the key habitat element for this species. It forages widely over many different types of vegetation and foraging habitat is not critical, nor are moths in short supply. (Note: this is a species to closely consider in our gypsy moth related projects.)

Since no caves occupied by Virginia big-eared bats are located on the Forest, the only potential impacts of gas leasing would be on foraging activities. Effects could include changes in canopy structure and increases in ambient noise which could affect the ability of the bats to locate food. Concerns about bats utilizing water from open impoundments with hydraulic fracturing fluids would be addressed in Alternative H by the standard requiring closed loop systems for those fluids. Site specific impacts would be addressed in the review of Applications for Permit to Drill.

James spinymussel (*Pleurobema collina*). The James spinymussel was federally listed as endangered in 1988. Historically, this species was apparently throughout the James River above Richmond, in the Rivanna River, and in ecologically suitable areas in all the major upstream tributaries (Clarke and Neves 1984). The species remained widespread through the mid-1960s, but now appears extirpated from 90% of the historic range. Extant populations and historical habitats on or near the National Forest are displayed in Table 3-75. This species is found in slow to moderate currents over stable sand and cobble substrates with or without boulders, pebbles, or silt (Clarke and Neves 1984). Hove and Neves (1994) found James spinymussels in 1.5 to 20 m wide second and third order streams at water depths of 0.3 to 2 m. Seven fish hosts, all in the family Cyprinidae, have been identified (Hove 1990): bluehead chub, rosyside dace, blacknose dace, mountain redbelly dace, rosefin shiner, satinfin shiner, and stoneroller. Freshwater mussels are filter feeders taking organic detritus, diatoms, phytoplankton, and zooplankton from the water column.

The following excerpt from Hove and Neves (1994) states the current thinking on threats: “There are several anthropogenic and natural threats to the James spinymussel’s continued existence. Nearly all the riparian lands bordering streams with the James spinymussel are privately owned. With more intensive use of the land, it is probable that water quality and habitat suitability will deteriorate. At present, the most detrimental activities include road construction, cattle grazing, and feed lots that often introduce excessive silt and nutrients into the stream.”

The introduced Asian clam is also considered to be a threat to the James spinymussel and is beginning to invade several sites (Hove and Neves 1994). Despite extensive searches on the Jefferson National Forest, the James spinymussel has been confirmed at only one site. This consisted on one live specimen found in 1990 (O’Connell and Neves 1991). A subsequent survey in 2001 failed to locate any live specimens at this site. Based on this information it is uncertain that the Forest supports a viable population of James spinymussel. The main avenues for the Forest to aid in this species recovery are through land acquisition, assisting in augmentation efforts, and working with landowners to protect streams and streamside habitat. See section titled “Aquatic Viability Determinations for Oil and Gas Leasing”

Potential impacts from horizontal drilling and hydraulic fracturing that could result from the decision to make lands available for leasing could include contamination of water from spills or accidents, increased sedimentation from clearing and construction activities, and effects on the quantity of water in streams. The potential for these impacts to occur is reduced through the use of the riparian standards in all alternatives. Further protection is provided in Alternative H through standards added to keep all drilling facilities out of riparian areas and standards to require: no withdrawal of surface water or groundwater from NFS lands (unless specifically approved due to reduced overall environmental impacts); only closed loop systems for hydraulic

fracturing; removal of drill cuttings from the drill site and disposal at approved site off NFS lands; secondary containment infrastructure; and no surface disposal of flowback water or produced waters. Other site specific impacts would be addressed in the review of Applications for Permit to Drill when the site specific nature of these impacts can be best analyzed.

Madison Cave isopod (*Antrolana lira*). The closest known Madison Cave isopod occurrences to National Forest, and the majority of potential habitat on National Forest are on the Lee and Pedlar Ranger Districts; the lands on these Districts are not underlain by Marcellus shale and do not have a high potential for gas development. In Alternative H these lands are not being made available for oil and gas leasing. There are 15 acres of National Forest System lands along US Highway 250 in Augusta County, west of Churchville that intersect with medium probability isopod habitat. In Alternatives A, B, D, E, G, H and I these lands are in the Scenic Corridor Management Area Prescription (7B). The emphasis of the Scenic Corridor prescription is to provide high quality scenery in sensitive recreational and travelway settings. These corridors and viewsheds are suitable for federal oil and gas leasing with controlled surface use, with the exception of no leasing in Alternative I. In Alternative C, these lands are allocated to the Unsuitable Mosaics of Wildlife Habitat Management Area Prescription (13U) and are not available for leasing. In Alternative F, these lands are allocated to the Recommended National Scenic Area Management Area Prescription (4FA) and are not available for leasing. Concern for impacts to Madison cave isopod habitat from horizontal drilling and hydraulic fracturing from the decision to make these 15 acres available for leasing in Alternatives A, B, D, E, G, and H includes loss or modification of karst aquifer habitat, groundwater contamination, or groundwater drawdown. The potential for these impacts to occur is reduced through the use of the riparian standards and forestwide standards. In Alternative H additional protection is achieved by added standards to keep all drilling facilities out of riparian areas to require: no withdrawal of surface water or groundwater from NFS lands (unless specifically approved due to reduced overall environmental impacts); only closed loop systems for hydraulic fracturing; removal of drill cuttings from the drill site and disposal at approved site off NFS lands; secondary containment infrastructure; and no surface disposal of flowback water or produced waters. Other site specific impacts would be addressed in the review of Applications for Permit to Drill when the site specific nature of these impacts can be best analyzed.

Exploration and production activity would have minimal, if any, effects to any TES species that may occur in the area. Most effects would be associated with exploration and development activities that disturb or destroy habitat that supports the occurrence of a TES species. All activities that involve leases will require the preparation of a Biological Assessment and/or Biological Evaluation that determines effects on the TES species and outlines appropriate mitigation measures. TES species, no matter where they occur within the lease area, will be protected to ensure viable populations and suitable associated habitat. Controlled surface use and timing stipulations along with application of forestwide and specific standards will reduce or eliminate most adverse impacts. Generally, specific locations of exploration and production activity is flexible, so impacts to TES species can be avoided by relocating the development and confining disturbance to previously disturbed areas. Federally listed species will require compliance with the Endangered Species Act with species protection and recovery objectives outlined in the Recovery Plan prepared for each species. All known occurrences of federally listed plants on the Forest site are protected within Special Biological Areas. These areas are available for Federal oil and gas leasing with controlled surface use stipulations to protect the plants and their habitat as well as other rare biological resources.

For state listed species, the Forest will cooperate fully with the protection and recovery objectives set forth by the state. All alternatives include the general goal of contributing towards the recovery of federally listed threatened and endangered species (T&E). Additionally, the following activities are common across all alternatives:

- Recovery plans (when available) will be followed for all T&E species;
- Forestwide population objectives for threatened, endangered, and candidate plants will be followed;
- Forestwide standards will be followed. For example, “sites supporting federally listed threatened and endangered species or individuals needed to maintain viability are protected from detrimental effects caused by management actions”;

- Threatened, endangered, and sensitive species will be conserved through the site-specific biological evaluation process;
- Surveys for all TES and their habitats will continue to be conducted on the Forest, particularly as part of the biological evaluation process in conjunction with projects likely to affect habitat for the species (project-level surveys would be conducted in accordance with procedures outlined in the Region 8 supplement of Forest Service Manual 2672);
- Monitoring of known populations of threatened, endangered, and sensitive species will be conducted consistent with Forest Manual direction.

Wildlife

The physical effects of oil and gas leasing upon wildlife include elimination of individuals that cannot move out of existing habitats being impacted by construction or reconstruction of access roads, clearing and leveling of drill pad sites, construction of pipelines and facilities, and road traffic associated with large truck movements during active drilling and production phases. Site access is developed by building a new road or improving an existing one. The potential impacts from new gas well development on the Lee, North River, Warm Springs, and James River Ranger Districts would vary by alternative:

Table 3D-20. Gas Well Development (includes federal and private lease activity)

Oil and gas activity for vertical and horizontal wells	GWNF Baseline RFD	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Number of wells	319	307	250	54	249	92	198	93	177
Total reclamation (total disturbance) (acres)	2,555	2,457	1,433	434	1,432	446	768	453	685

Currently, there are no leases for Marcellus shale gas wells on the Lee, North River, Warm Springs, and James River Ranger Districts. Road and drilling pad construction would result in the creation of edge and a reduction of forest interior habitat. Creation of edge can result in an increase in cowbird parasitism and predation upon a variety of species. Given the Lee, North River, Warm Springs, and James River Ranger Districts are in a generally forested landscape, the expected negative impacts of edge are not considered significant. Forest interior habitat will be lost as a result of road construction and creation of drilling pads. This loss is considered to be similar for each alternative, thus habitat for the ovenbird, a forest interior management indicator species, will be reduced for all alternatives. Conversely, creation of edge and early seral habitat can benefit some species, such as white-tail deer, black bear, and wild turkey. Early successional bird species, such as indigo buntings, eastern towhees, and field sparrows may benefit from the resulting open and brushy habitats created from RFD of oil and gas resources. Habitat for the eastern towhee, an early successional habitat management indicator species, will be improved under all alternatives. Habitat for white-tailed deer, black bear, and wild turkey will be improved, but hunting opportunities could be limited near the well sites due to road traffic volume during active drilling and production phases.

Non-Native Invasive Plants

The Chief of the U.S. Forest Service (USFS) has identified non-native invasive species as one of the four critical threats to USFS ecosystems. As defined in Executive Order 13112 issued February 3, 1999, an invasive species is one that meets the following two criteria: “1) it is nonnative to the ecosystem under consideration and, 2) its introduction causes or is likely to cause economic or environmental harm or harm to human health.”

In the United States, invasive species are reported to be the second-most critical threat to conservation of biodiversity (Wilcove et al. 1998). Nonnative plants are known to occur across Southern and Central Appalachian forests, often accounting for 25% or more of the documented flora. While not all non-native

species are known to disrupt native ecosystems, of particular concern are those that are successful at invading and rapidly spreading through natural habitats. Invasive plants create a host of harmful environmental effects to native ecosystems including: displace native plants; degrade or eliminate habitat and forage for wildlife; threaten endangered species; impact recreation; affect fire frequency; alter soil properties; decrease biodiversity; and more. Invasive plants spread across landscapes, unimpeded by ownership boundaries. Infested areas represent potential seed sources for continuation of the invasion on neighboring lands.

Ground disturbance creates opportunities for establishment and spread of non-native invasive species. The amount of ground disturbance from new gas well development on the Lee, North River, Warm Springs, and James River Ranger Districts would vary by alternative:

Table 3D-21. Gas Well Development (includes federal and private leasing activity)

Oil and gas activity for vertical and horizontal wells	GWNF Baseline RFD	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Number of wells	319	307	250	54	249	92	198	93	177
Total reclamation (total disturbance) (acres)	2,555	2,457	1,433	434	1,432	446	768	453	685

Currently, there are no leases for Marcellus shale gas wells on the Lee, North River, Warm Springs, and James River Ranger Districts.

Ground disturbance caused by activities associated with Marcellus gas development includes road construction, well pad construction, pipeline construction and maintenance, and off-site facility construction. Ground disturbance creates habitat suitable for NNIP infestations. Roads and pipelines are corridors for NNIP to move through the landscape. The potential for NNIP infestation and movement increases with the amount of ground disturbance. Alternative A has the most acres of potential ground disturbance and therefore has the greatest potential for NNIP establishment. Alternatives B, D, and F would have 23% to 55% less ground disturbance than Alternative A and consequently as proportionately reduced threat of NNIP infestation. Alternatives C and I, E, and G would have a 283% to 565% reduced threat of NNIP infestation versus Alternative A. The potential for NNIP infestations from ground disturbing activities could be offset by specifying aggressive NNIP treatments when authorizing special use permits.

Potential Wilderness Areas and Inventoried Roadless Areas

Development of gas wells in areas of high gas potential could affect Potential Wilderness Areas and Inventoried Roadless Areas on the North River, James River and Warm Springs Ranger Districts. In Alternatives B, D, E, F, G, and H areas allocated to the Remote Backcountry Management Prescription Area would be leased with a no surface occupancy stipulation so there would be no impacts to those areas. Impacts would occur in those alternatives that would allow some form of “active management” in portions of the Potential Wilderness Areas or Inventoried Roadless Areas. These portions of lands would be administratively available under standard lease terms, timing stipulations and controlled surface use stipulations. However, for those portions that are in IRAs, in order for any exploration/development activities to be consistent with the 2001 RACR, they would have to be leased with stipulations that would prohibit any new road construction/reconstruction and limit the amount of tree removal that could occur. Table 3D-22 displays the Inventoried Roadless Area acres potentially affected by gas development by alternative.

Table 3D-22. Inventoried Roadless Areas Potentially Affected by Gas Development

Potential Wilderness Name	Potential Wilderness Area Acres	Inventoried Roadless Area Acres	Acres of Inventoried Roadless Area under Standard Lease Terms, Timing Stipulations or Controlled Surface Use Occupancy Stipulations							
			Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Archer Knob	7,100									
Beards Mountain	10,200	7,500	7,500							
Beech Lick Knob	14,100									
Crawford Knob	14,900	9,900	9,900	1,200		1,400				
Elliott Knob	11,100	9,400	9,400	200						
Galford Gap	6,700									
Gum Run	14,500	12,600	12,600							
High Knob	18,400	12,900	12,900	500						
Jerkemtight	27,300	16,800	16,800	800		800				
Laurel Fork	10,200	10,000	10,000							
Little Alleghany	15,400	10,200	10,200	700		1,000	1,000			
Little River	30,200	27,200	27,200	1000						
Oak Knob - Hone Quarry Ridge	16,300	10,800	10,800	800		1,200				
Oliver Mountain	13,000	13,000	13,000							
Paddy Knob	6,000									
Potts Mountain	7,000									
Ramseys Draft Addition	19,100	12,800	12,800							
Rich Hole Addition	12,200	10,900	10,900	1,500		1,500	1,500			
Rich Patch	900									
Rough Mountain Addition	2,100	1,200	1,200							
Shaws Ridge	7,300									
Total	264,000	165,200	165,200	6,700	0	5,900	2,500	0	0	0

Table 3D-23 displays those portions of the Potential Wilderness Areas (that are not in IRAs) potentially affected by gas development

Table 3D-23. Acres of Potential Wilderness Areas (That are Not in IRAs) Potentially Affected by Gas Development

Potential Wilderness Name	Potential Wilderness Area Acres	Inventor-ied Roadless Area Acres	Acres of Potential Wilderness Area (Not in IRAs) under Standard Lease Terms, Timing Stipulations or Controlled Surface Use Occupancy Stipulations							
			Alt A	Alt B	Alts C & I	Alt D	Alt E	Alt F	Alt G	Alt H
Archer Knob	7,100		7,100	7,100		7,100		7,100	2,200	2,000
Beards Mountain	10,200	7,500	2,600			1,800		1,800	1,800	1,900
Beech Lick Knob	14,100		14,100	8,500		8,500			5,800	4,900
Crawford Knob	14,900	9,900	5,000	5,000		5,000	2,500	2,500	5,000	5,100
Elliott Knob	11,100	9,400	1,700	1,700		1,700	1,700		1,700	4,400
Galford Gap	6,700		6,700	6,700		6,700	6,700		6,700	6,700
Gum Run	14,500	12,600	1,900	1,900		1,400				
High Knob	18,400	12,900	5,600	5,600		5,300			4,100	4,100
Jerkemtight	27,300	16,800	10,500	10,500		10,400	4,300	4,300	3,600	5,000
Laurel Fork	10,200	10,000	200	200						
Little Alleghany	15,400	10,200	5,200	5,200		5,200	5,200		5,000	5,100
Little River	30,200	27,200	3,000	3,000		2,400		2,400	1,500	1,400
Oak Knob - Hone Quarry Ridge	16,300	10,800	5,500	5,500		4,400				
Oliver Mountain	13,000	13,000	0							
Paddy Knob	6,000		6,000	6,000		5,100	5,100		5,100	5,000
Potts Mountain	7,000		7,000	7,000		7,000			7,000	6,700
Ramseys Draft Addition	19,100	12,800	6,300	6,300		5,400	4,700		3,400	3,600
Rich Hole Addition	12,200	10,900	1,200	1,200		1,200	1,200		1,000	1,000
Rich Patch	900		900	900						
Rough Mountain Add	2,100	1,200	900	900		800			900	800
Shaws Ridge	7,300		7,300	7,300		7,200				
Total	264,000	165,200	98,700	90,500	0	86,600	31,400	18,100	54,800	57,700

Development of gas wells and associated pipelines and roads in Potential Wilderness Areas would likely result in a loss of wilderness character in the area of the disturbance and could result in a loss of wilderness character in the entire Potential Wilderness Area.

Recreation

The Reasonably Foreseeable Development (RFD) for federal oil and gas uses the assumption that the entire is George Washington National Forest is open to federal oil and gas leasing except areas withdrawn by law, specifically designated Wildernesses and the Mount Pleasant National Scenic Area. The recreation opportunity settings of the national forest are inventoried using the Recreation Opportunity Spectrum (1986 ROS Book, USDA Forest Service). The spectrum of settings ranges from primitive to urban. Settings inventoried on the George Washington National Forest include semi-primitive non-motorized (SPNM), semi-primitive motorized

(SPM), roaded natural (RN), and rural (R). There are no areas on the Forest that meet the inventory criteria for the two extreme ends of the spectrum: primitive and urban.

There are approximately 995 miles of national forest system trails within the baseline RFD area, excluding trails in designated Wildernesses and the National Scenic Area. These trails are multiple-use, most allowing hiking, horseback riding and mountain biking. Three trails that total 65 miles allow motorized use. Hunting and some fishing are common dispersed recreation activities.

There are 59 developed recreation areas within the RFD area, and an additional 52 developed sites that support dispersed recreation.

Oil and natural gas development would affect recreation activities primarily in terms of the degree to which the settings and patterns of use are changed due to development operations. There are 847,566 acres, or 80% of the George Washington National Forest, in federal mineral ownership and not withdrawn from mineral leasing by law. Access road construction, gas well pad construction, gas pipeline construction and drilling operations could impact the developed and dispersed recreation visitors' experience and the recreation settings.

The sights and/or sounds of gas development activities may negatively impact the experience of recreationists using trails or recreating off-trail in the general forest area in the vicinity of lease activity, particularly during the drilling operation, pipeline construction and subsequent maintenance periods. A short-term result would be use pattern changes in the form of avoidance and displacement to other areas. A normal drilling operation would require about three months, beginning with site clearing and ending with site restoration. With production operations, the disturbance would normally be limited to the immediate area of the wellhead and the access road.

The RN setting allows human-made structures such as wellheads but these are generally scattered and remain visually subordinate from sensitive travelways. In the RN setting, remoteness is of little relevance due to the expected proximity to roads and/or facilities. However the semi-primitive settings provide opportunities for remote, backcountry recreation where there is little evidence of human-made structures other than trails and their associated signs and structures. Some vestiges from the past may be evident, but have been substantially reclaimed by nature. Examples include old narrow gauge railroad grades and logging roads. Within RN settings and given the latitude for well pad location contained in existing regulations, the negative impacts of leases can usually be mitigated during the production phase. Long-term, site restoration would allow the RN criteria to be met. Lease stipulations or Conditions of Approval on Surface Use Plans of Operations would ameliorate or eliminate impacts in some cases.

Within SPM and SPNM settings, a natural, unmodified environment should dominate. Areas of inventoried SPNM and SPM recreation settings that are allocated to prescription areas where federal oil and gas leasing is not available or would have a No Surface Occupation stipulation include Wilderness, recommended Wilderness, Appalachian Trail corridor, research natural area, designated National Scenic Area, recommended National Scenic Area and remote backcountry. These acres of semi–primitive settings are substantially protected and there would be little impacts to them.

In SPNM and SPM settings, there should be no permanent roads, on-site management controls should be subtle, and within SPNM areas there should be no motorized use. The construction, operations and maintenance of roads, wells, pipelines, their permanent presence in the setting, and the increased interactions between Forest visitors to these settings and lessees and contractors are not consistent with the experience characterization for SPM and SPNM. The table below shows acres of SPNM and SPM that are allocated to prescription areas that would be available for oil and gas leasing with either controlled surface occupancy, a timing stipulation or standard lease terms.

Table 3D-24. Summary of Semi-Primitive Settings Available for Oil and Gas Leasing With Surface Occupancy by Alternative

Stipulations and Terms	Alt A	Alt B	Alts C and I	Alt D	Alt E*	Alt F	Alt G	Alt H**
Controlled Surface Occupancy Stipulation, SPNM+SPM acres	5,856	5,615	0	5,395	5,367	5,320	5,384	75,016
Timing Stipulation, SPNM+SPM acres	656	0	0	659	659	659	659	0
Standard Lease Terms, SPNM+SPM acres	183,863	167,512	0	177,968	125,643	107,763	134,355	0
Summary of SP Acres Available for Oil and Gas Leasing	190,375	173,127	0	184,022	131,670	113,742	140,398	75,016

*Under Alt E, no horizontal drilling and associated hydraulic fracturing operations will be allowed.
**Under Alt H, all SPNM and SPM areas with a controlled surface use occupancy have a limit on road construction.

Based upon the baseline RFD, anticipated minerals activities and the resultant impacts from potential new gas well sites, associated roads, pipeline clearing and disturbance, following are the alternatives descending from greatest impacts to less impacts: Alternative A, Alternative D, Alternative B, Alternative G, Alternative E. Impacts may be mitigated by the Conditions of Approval on Surface Use Plans of Operations under all of the alternatives.

All of the developed recreation sites would be protected from direct effects of gas production by the Controlled Surface Use stipulations or Conditions of Approval on Surface Use Plans of Operations under all of the alternatives. However, there is some potential for recreationists to hear or see evidence of gas development activities taking place near the recreation site. These would normally be short- term impacts during production periods.

There is potential for roads and pipelines constructed to support oil and gas development and operations to impact trails and trail users. Direct impact to trails would occur in instances where access roads or pipelines cross them. Roads generate noise, dust, and safety concerns. Storm water runoff from roads and maintenance operations can potentially damage trails.

Alternatives C and I would have the least impact on trails, followed by Alternatives E and G. The alternative that would likely have the most impacts on trails is Alternative A. It has the greatest potential for occurrences of crossings or close proximity to trails that would impact trails and trail users. The alternatives with the next greatest potential for impacts to trails are Alternatives B and D. These effects may be mitigated, to varying degrees, through rehabilitation, management controls, and/or trail relocation. Lease stipulations or Conditions of Approval on Surface Use Plans of Operations would ameliorate or eliminate impacts in some cases.

As of September 2010, existing federal oil and gas leases were in effect on 1.2% of the George Washington National Forest lands. Considering both potential federal leases and potential private minerals development on national forest land, and the resultant impacts from expected new gas well sites, associated roads, pipeline clearing and disturbance, Alternative A would have the greatest impacts on recreation resources, followed by Alternative D.

Scenery

The scenic resource is affected by management activities altering the appearance of what is seen in the landscape. Short-term scenic effects are usually considered in terms of degree of visual contrast with existing or adjacent conditions that result from management activity. The scenic landscape can be changed over the long-term or cumulatively by the alteration of the visual character. Management activities, which result in visual alterations inconsistent with the assigned SIO, even with mitigation, affect scenery. Management activities that

have the greatest potential of affecting scenery are road construction, vegetation management, insect and disease control, special use utility rights-of-ways, and mineral extraction.

Mineral management and development activities can involve major alteration to landform, as well as contrasts to form, line, color, and texture, causing substantially adverse scenic impacts. Natural gas drilling and production are not common on the George Washington National Forest. To date there have been only five exploration wells and no wells have gone to production. Currently, the activities associated with minerals involve shale pits, limestone extraction and surface collection of building rock. New activities associated with federal oil and gas leasing will impact scenery.

The most significant visual impacts from natural gas well development would occur during the drilling operation and subsequent maintenance periods. Drilling rigs and other equipment would give the area an industrial look that is out of character with the surrounding landscape. The negative visual impacts from drilling would include the construction of well pads, access roads and pipelines along with the operation and sight of the necessary drilling equipment. A normal drilling operation would require several months, beginning with site clearing and ending with site restoration. The areas are moderate to steeply slope and there may be some steep cut slopes that would likely be necessary in the construction of roads and well pads. The following table shows the potential development of roads, pipelines, and well pads by alternative.

Table 3D-25. Oil and Gas Leasing Activities by Alternative That Affect Scenery (includes federal and private leasing activity)

Activity	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Roads (miles)	237	120	42	119	32	47	32	42
Pipelines (miles)	260	131	46	131	35	52	35	46
Well pad (acres)	597	486	106	486	183	386	185	344

Based upon the Reasonably Foreseeable Development (RFD) scenario, potential minerals activities and the resultant impacts from expected new gas well sites, associated roads, pipeline clearing and disturbance to soils, the alternatives rank, in descending order, from the greatest impacts to the least impacts as follows:

Alternative A, B, D, H, F, and E. Related to oil and gas leasing, Alternatives C and I would have no impact on scenery.

Potential maximum direct, indirect and cumulative effects to scenery resources can be assessed according to the maximum extent within which the characteristic landscape is altered, including changes to line, color, texture and scale. Ground-disturbance, grading and vegetation clearing activities can potentially occur for all alternatives except Alternatives C and I. The principal proposed activities that could alter the characteristic landscape include construction of roads, well pads and pipelines. Cumulatively, the repeated implementation of these project activities could, over time, result in the degradation of scenery.

Cultural Resources

The George Washington National Forest contains a multitude of sites representing past human events. Beginning with Native American occupations dating as early as 8000 B.C., the variety of cultural resources is impressive. Prehistoric sites include multi-use base camps, transient camps, hunting and gathering stations, quarries, lithic reduction stations, and rock-shelter occupations. The most common site type is often referred to as a lithic scatter and represents a short-term occupation where stone tools were made and/or sharpened and may be associated with a plethora of ancillary activities. Native American sites are found throughout the Forest for all time periods with the exception of the Ice Age Paleoindians. Unknown Paleoindian sites may exist on the Forest but have yet to be located. Cultural resources are important resources that require inventory, evaluation, protection, and interpretation.

Direct and indirect affects to historic or cultural resources could result from both natural and human-caused events. These vary depending upon the type of resource, the fragility of the resource, and the type of disturbance, but could include soil disturbance to varying depths, vegetation removal, looting or vandalism, and land use changes.

Accordingly, five types of ground disturbing land management activities that vary in magnitude (acres or miles) have the greatest potential to affect cultural resources. These include: timber management, road construction, fire management, mineral management, and recreation use. To a lesser degree, other forms of land management, such as landownership adjustment (land exchange), special use permits, structures management, and wildlife management can also affect cultural resources.

Exploration and development of leasable minerals, oil, gas, and mineral materials may impact cultural resources through access road construction, pipeline construction, well pad placement, and actual removal and displacement of minerals and soil. Mineral extraction may produce severe, albeit localized, direct effects to significant cultural resources as the overburden containing historic resources are removed. Indirect effects could include damage to significant cultural resources located outside the area of immediate mining resulting from erosion, the installation of road accesses and equipment staging areas, and vandalism and looting resulting from increased access to these historic properties.

Apart from these common effects, potential maximum direct, indirect and cumulative effects to cultural resources can be assessed according to the maximum extent within which ground-disturbing activities can potentially occur for each alternative. The principal proposed ground-disturbing activities include construction of roads and well pads. Cumulatively, the repeated implementation of these project activities could, over time, result in the degradation of sites, a potential reduction in the number of intact historic properties, and increased site vandalism.

Analysis of effects of minerals management to significant cultural resources is performed programmatically in compliance with existing laws and regulations (e.g., 36 CFR 296, 800, and the PA with the Virginia SHPO) and occurs on a case-by-case basis separate from alternatives. Therefore, effects to cultural resources resulting from minerals management are not affected by alternative.

Mineral Resources

The combustion of fossil fuels in the drilling, hydraulic fracturing, and production of vertical and horizontal wells for natural gas is evaluated in a recent Environmental Impact Statement by New York State (New York State Department of Environmental Conservation 2011). Data from the report is used to estimate the diesel/gasoline consumption of drilling, hydraulic fracturing, and production of vertical and horizontal wells for natural gas by alternative.

Table 3D-26. Estimated diesel/gas consumption for federal oil & gas lease operations (thousands of gallons)

Decade	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Decade 1 annual average	802	553	0	553	68	421	69	400
Decade 1 total	8,020	5,531	0	5,531	678	4,217	692	4,002
Decade 2 annual average	807	818	0	818	81	485	71	386
Decade 2 total	8,074	8,178	0	8,178	809	4,847	710	3,864
Decade 3 annual average	19	206	0	206	24	127	17	87
Decade 3 total	1,899	2,060	0	2,060	243	1,268	167	871

In addition to consumption by combustion, natural gas is lost by fugitive emissions, venting and flaring. These losses are expected to vary by alternative in a similar way as the alternatives vary by diesel/gasoline consumption.

The cumulative consumption of gasoline/diesel by potential federal oil and gas operations is shown and added to the subtotal in Table 3D-26.

Table 3D-27. Estimated gas/diesel consumption for decade 1 (millions of gallons)

Program	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Forest Administration*	1.0	1.2	0.7	1.9	1.2	0.9	1.2	1.2
Timber Harvest	6.6	7.8	0.0	14.8	4.4	2.7	7.7	7.7
Recreation*	40.0	41.0	36.0	40.0	36.0	44.0	41.0	41.0
SubTotal	47.6	50.0	36.7	56.7	41.5	47.6	50.0	50.0
Potential Federal Oil & Gas	8.0	5.5	0.0	5.5	0.7	4.2	0.7	4.0
Total	55.6	55.6	36.7	62.2	42.2	51.8	50.7	54.0

*Based on midpoint of range in annual gas/diesel consumption tables

Social and Economic Resources

INTRODUCTION

The Reasonably Foreseeable Development (RFD) of federal oil and gas leasing on the GWNF concentrated on development of the Marcellus shale formation; therefore, this section focuses on potential effects from development of that formation. Development of the Marcellus shale gas play on and near the George Washington National Forest would bring natural gas drilling and production activity to areas that have seen little or no such activity in the past. Descriptions of the existing social and economic environments for the GWNF at local and regional levels are presented previously in Chapter 3, Section C12, Social and Economic Impact Analysis. This section describes the potential effects of Marcellus shale development on social characteristics, such as demographics and quality of life, and on economic characteristics, such as employment, income, economic diversity and federal payments.

There are a number of factors to consider when determining the social and economic impacts resulting from the extraction of natural gas. Kay (2011) suggests that the most important factors are related to pace and scale, i.e. the rate of development, the length of time over which the development occurs, and the geographic distribution of the development. Christopherson (2010) lists the following factors that may affect the pace and scale of Marcellus Shale drilling: transportation costs; current tax policies; speculative investments; competition among and access to capital by natural gas companies; rig availability; regulatory requirements and capacity; and status of other natural gas sources, such other deep shale plays. Kay (2011) identifies various drivers for the pace of drilling that include: the need to initiate production or risk losing it or having to renegotiate leases on less favorable terms (hold by production); futures markets for gas; production incentives related to joint venture agreements; the internationalization of capital investment in shale gas drilling; capitalization strategies that emphasize production over profit; well drilling technology; Marcellus productivity; and regional geology. Considine (2010b) adds geology differences and politics to the list. Christopherson and others (2011a) give two ways to forecast the pace and scale of drilling in a shale gas play. The first is based on what is geologically and technologically possible: an analysis of total potential natural gas reserves and the

capacity of existing or anticipated technologies. The other is based on business dynamics in the energy industry, and looks at what are the likely strategies of energy firms in response to their profit opportunities in particular shale plays and overall.

AFFECTED ENVIRONMENT

There is no current development of any natural gas formations on the GWNF. Although there are existing federal leases and private mineral rights within the Forest, there are no known future plans for development.

Current economic and social characteristics of the 17 counties with GWNF lands are described in Chapter 3, Section C12. Of particular interest, are five Virginia counties where there is over 20% of the total county acreage in GWNF lands underlain by Marcellus shale resources. These counties include: Alleghany (30%), Augusta (23%), Bath (28%), Highland (22%) and Rockingham (22%). Similarly, Pendleton County, West Virginia has 11% of the total county acreage where the Marcellus shale underlies GWNF lands. Botetourt, Page, Rockbridge, Shenandoah Counties in Virginia and Hampshire and Hardy Counties in West Virginia have between 1% and 3%. The following table highlights some of the current social and economic indicators for the counties with more than 10% of total acreage of GWNF lands with Marcellus shale. Although the geographical distribution of wells and the inter-relationships between counties would be influencing factors, these counties may be the ones that experience a higher degree of additional incomes, job opportunities, federal payments and other benefits as well as negative effects such as competition for tourism businesses and strains on infrastructure and landscape amenities if development occurs on GWNF lands in those counties.

Table 3D-28. Counties with More than 10% of Total Acreage that have GWNF Lands with Marcellus Shale Resources.

County or Independent City	Per Capita Income in 2010	Unemployment Rate in 2011	People Below Poverty in 2010	Employment in Travel and Tourism Sector in 2009	Forest Service Payments (2011$)
Alleghany County, VA	$22,013	8.3%	13%	18%	332,179
Covington city, VA	$20,781	9.2%	n/a	15%	n/a
Augusta County, VA	$23,571	6.0%	12%	9%	459,872
Staunton city, VA	$24,077	6.9%	n/a	19%	n/a
Waynesboro city, VA	$23,190	7.9%	n/a	19%	n/a
Bath County, VA	$22,083	5.4%	10%	45%	394,192
Highland County, VA	$25,690	7.0%	9%	18%	118,499
Rockingham County, VA	$25,274	5.5%	18%	13%	430,551
Harrisonburg city, VA	$16,750	7.3%	n/a	23%	n/a
Pendleton County, WV	$19,401	6.5%	15%	18%	401,776

DIRECT AND INDIRECT SOCIAL AND ECONOMIC IMPACTS

SOCIAL

The potential social impacts of Marcellus shale development include both positive and negative effects on indicators of community, such as population, housing, local government services, and quality of life. The magnitude of these effects can vary based on the overall pace and scale of natural gas development. Since gas drilling on the GWNF would be a new industry in the local economy, a sizeable start of development could have concerns for localized and abrupt effects on housing markets, tourism, community services and infrastructure.

Increased demand for housing from nonlocal gas workers could bring in additional income, but it could also increase rates that are no longer affordable to local residents or tourists (Alter et al. 2010). A less diversified local economy could experience competition for resources related to housing, labor or materials, resulting in a 'crowding out' effect, such as availability of hotels versus tourists (Kay 2011).

Tourism-related businesses, such as restaurants, hotels and shopping venues, can benefit from an influx of nonlocal gas industry employees. However, the industry's demand for these businesses could strain the ability of these businesses to provide services for local residents and visitors (Kay 2011; Christopherson et al. 2011a).

The visual impacts of drilling are related to the well pads, drilling rigs, compressor stations, water storage, equipment depots, access roads, pipelines, etc. Drilling rigs can reach a height of 150 feet or more, but the degree of impact can vary depending on viewing distance and surrounding landscape character. During the drilling phase, these rigs operate 24 hours a day, creating night time impacts that include rig lighting and open flaring. On a small scale, the impacts may be insignificant but cumulatively, the greater the extent of drilling, the greater the potential of changing the visual environment from a scenic landscape to a more industrial landscape (Rumbach 2011).

The rural and outdoor amenities that are associated with environmental tourism often provide a key attraction for visitors as well as young professionals and retirees who move to an area. Outdoor recreation and sporting amenities (hunting, fishing, and water-related activities) contribute to an area's quality of life, or community character. The preservation and maintenance of those amenities can be an important component of an area's sustainable economic development strategy (Rumbach 2011). Therefore, if the environmental impacts from natural gas development become negative, an area may suffer decreases in tourism or population growth.

Christopherson and Rightor (2011b) note that while access roads to well sites are usually adequately designed, constructed and maintained, there are other roads that are used by the trucks that are not designed to withstand the volume, weight and dust associated with this level of truck traffic. This could be mitigated to some extent through weight permitting, bonding provisions and other methods by local communities but there could be additional social and economic effects on local governments and residents.

Another positive social effect from natural gas production comes from the eventual use of a relatively clean source of energy. A reduction in the demand for oil or coal would result in a decrease in carbon dioxide emissions and other air pollutants such as sulfur and nitrogen (Kinnaman 2010).

ECONOMIC

Economic impacts include potential effects on employment, income, revenues and expenditures. The typical methodology for evaluating economic impacts involves the use of an input-output economic impact model that measures how different amounts of a product or service create direct, indirect and induced effects on employment and income. Most of the studies estimating the economic impacts from Marcellus shale development have used the IMPLAN (Impact for Planning Analysis) model, which is the model the Forest Service uses. IMPLAN is an economic model originally developed by the Forest Service, Federal Emergency Management Agency and the Bureau of Land Management. IMPLAN has since been privatized and is now provided by Minnesota IMPLAN Group (MIG). It uses a database of economic statistics obtained from major government sources such as the Regional Economic Information System (REIS), Bureau of Economic Analysis, Bureau of Labor Statistics and US Census Bureau.

There are a number of studies that have addressed the economic impacts of the Marcellus shale industry through the use of input-output economic models: The Perryman Group 2008; Considine 2010b; Considine, Watson, and Blumsack 2010a; Barth, 2010; Higginbotham 2010; and Kelsey and others 2011. However, since Marcellus shale drilling using high-volume hydraulic fracturing techniques is a relatively new industry that has become established rather rapidly in some areas, some of these studies have been subject to various criticisms, such as lack of extensive experience and empirical data (Kay 2011; Kinnaman 2010) or assumptions made concerning the amount of leakage for a newly developing industry in a region (Kay 2011; Kelsey 2011; Kinnaman 2011). Another caution for comparing these studies to the potential effects on the

local economy for the GWNF area is that all of these studies assumed that the gas development and production occurred on private lands, not public lands. Income that is derived from leasing fees, bonuses and royalties to private landowners (including how those landowners then spend that money) can differ from those made to the Unites States Treasury on public lands. Despite criticisms concerning these studies, they are worth mentioning because they all show substantial increases in jobs and income from development of the Marcellus shale gas play.

EMPLOYMENT

In 2009, the Marcellus Shale Education and Training Center conducted a Marcellus Shale Workforce Needs Assessment (MSETC 2009). They identified three labor forces associated with the development of Marcellus shale: direct, indirect and induced labor. Direct labor jobs are directly involved in the drilling and production phases. These direct labor jobs include occupations associated with staking, scoping, permitting, engineering, logging, clearing, drilling, moving, finishing, cementing, completing, fracturing, and producing a well, as well as the majority of jobs required to clear, dig, and construct collector pipeline and compressor station infrastructure for the well. Indirect labor includes the supply-chain industries such as quarries, real estate, machinery manufacturers, etc. Induced labor includes such items as housing, food and drink, and retail, when purchased from household spending of income earned either directly or indirectly from the industry spending.

The drilling phase of gas development typically depends on a workforce that is out of the region of development, except for truck haulers and construction jobs. The majority of drilling phase jobs include the 'roughnecks' who work on drilling rigs, excavation crews, CDL (tractor-trailer) drivers, heavy equipment operators, hydro-fracturing equipment operators, and semi-skilled general laborers. Development of the Marcellus shale is more industrial in nature, technologically advanced and labor intensive than the more traditional shallow natural gas drilling (Christopherson et al. 2011a). The production phase tends to rely on local employment that include well operators, instrumentation technicians, pipefitting and welding technicians, production engineers, and office staff (Christopherson et al. 2011b; Jacquet 2011). The Marcellus Shale Education and Training Center assessment (MSETC 2009) found that 98% of jobs are concerned with the development of the gas well and are not needed after the well has been drilled. Only 2% of jobs are concerned with the long-term production of the well. However, as the gas industry becomes more established in a region, the workforce may become more local as training opportunities develop in the region, companies may set up operations closer to the region and nonlocal employees may relocate to the region (Jacquet 2011).

The MSETC also performed a number of regional workforce needs assessments focused on the Marcellus shale gas industry in Pennsylvania. They have found that approximately 250 different occupations comprised of over 400 different individuals are required to drill a Marcellus Shale well. However, a typical high-volume hydraulic-fracturing well is constructed over a three to four month period. The vast majority of these individuals and occupations are required for only a few hours or days for each well. The number of Full Time Equivalent (FTE) workers (an FTE is equal to one worker working full time for a year) for these 410 individuals was about 13 FTEs to complete a well. Only one FTE is required to operate and maintain every six wells in production but that FTE is needed for the life of the wells, about 30 years (MSETC 2009, 2010).

To identify the contribution to employment from Marcellus shale gas development on the GWNF, the IMPLAN model was used to identify the economic linkages among the industrial sectors within the local economy and how those industries respond to the development. For purposes of estimating the economic impact on jobs and labor income from natural gas development, the counties and their independent cities that contain GWNF acreage were selected as the impact area for the IMPLAN model. However, estimating the impacts from new development of a gas play using the IMPLAN model can be different than estimating the impacts from other resource outputs, such as timber and recreation which can be predicted at a fairly steady rate over a time period and based on historical data. Input-output analysis relies on tables of coefficients that link one industry to all other industries. In a region where gas drilling has not existed in the past, it is impossible to know what those area-specific inter-industry coefficients will be, and "borrowing" them from other regions or industries can result in inaccurate impact conclusions. The most important use of the model for our local economy is to compare relative economic effects among the alternatives. The results should not be viewed as absolute economic values that accurately portray the infinitely complex economic interactions of the regional economy.

Tables 3D-29 and 3D-30 illustrate how the proposed alternatives potentially affect jobs in the local economy for the GWNF. The table represents the jobs from outputs from other resource outputs as described in Chapter 3, Section C Tables 3C12-19 and 3C12-20, plus development of Marcellus shale gas on federal and private leases within the GWNF. In the IMPLAN model, jobs can be part-time, full-time or seasonal. Currently, there are 857 jobs related to the Minerals industry within the local economy (Chapter 3, Section C, Table 3C12-6), none of which are influenced by activities on the GWNF since there is no current gas production on GWNF lands. As the table below shows, the development of Marcellus shale on the GWNF would significantly increase the numbers of jobs.

Table 3D-29. Employment by Resource Activity by Alternative (Average Annual, Decade 1, jobs contributed), with Marcellus Shale Gas Development on GWNF lands (includes development on existing federal leases and private mineral rights)

Resource	Alt A	Alt B	Alt C	Alt D	Alt E	Alt F	Alt G	Alt H	Alt I
Recreation	78	79	67	83	74	83	80	80	80
Wildlife and Fish	52	53	44	55	49	55	54	54	54
Timber	88	106	0	199	60	38	106	110	110
Minerals	2,978	2,255	536	2,255	763	1,850	767	1,775	536
Payments to States/Counties	64	64	64	64	64	64	64	64	64
Forest Service Expenditures	351	321	299	332	318	314	322	322	322
Total Forest Service Management	3,611	2,878	1,011	2,989	1,328	2,404	1,393	2,404	1,166

Employment divided among the major industrial sectors of the local economy is shown in the following table. For more information on the definition of the industrial sectors, see the Economic Affected Environment section in Chapter 3, Section C12. The development of natural gas under each alternative has by far the greatest impact on employment than any other resource activity on GWNF lands.

Table 3D-30. Employment by Major Industry by Alternative (Average Annual, Decade 1, jobs contributed), with Marcellus Shale Gas Development

Industry	Alt A	Alt B	Alt C	Alt D	Alt E	Alt F	Alt G	Alt H	Alt I
Agriculture	67	76	6	125	45	33	75	77	77
Mining	2,365	1,789	427	1,789	604	1,467	607	1,409	427
Utilities	4	3	1	4	2	3	2	3	2
Construction	103	78	23	79	29	65	29	63	26
Manufacturing	17	20	3	39	10	10	16	19	18
Wholesale Trade	29	24	11	26	15	21	16	22	15
Transportation & Warehousing	34	28	12	31	16	24	18	25	16
Retail Trade	146	120	58	128	75	106	80	107	76
Information	8	7	3	7	3	6	4	6	5
Finance & Insurance	42	34	12	36	16	28	17	28	15

Industry	Alt A	Alt B	Alt C	Alt D	Alt E	Alt F	Alt G	Alt H	Alt I
Real Estate & Rental & Leasing	51	40	15	43	21	34	22	34	18
Prof, Scientific, & Tech Services	74	57	19	59	26	48	27	47	22
Mngt of Companies	12	10	2	10	4	8	4	8	3
Admin, Waste Mngt & Rem Service	40	33	13	35	17	27	18	28	15
Educational Services	14	11	4	12	5	9	6	10	5
Health Care & Social Assistance	102	80	28	86	40	66	43	68	35
Arts, Entertainment, and Recreation	36	33	21	35	24	31	26	31	24
Accommodation & Food Services	115	100	58	107	71	93	76	93	64
Other Services	59	47	16	51	22	38	24	40	19
Government	292	288	280	289	283	286	284	287	283
Total Forest Management	3,611	2,878	1,011	2,989	1,328	2,404	1,393	2,404	1,165

INCOME

The spending by Marcellus producers has ripple effects throughout the economy. For example, drilling companies hire trucking firms to haul pipe, water, and other materials to a well site. This trucking firm buys fuel and other supplies to supply these services and hires drivers to operate the trucks. The truck suppliers in turn acquire goods and services from other firms, such as repair shops, parts distributors, and other suppliers. So Marcellus investment sets off a business-to-business chain of spending throughout the economy. These economic impacts are known as *indirect* impacts. When the drivers go out and spend their paychecks, that spending stimulus sets in motion a similar chain reaction, known as *induced* impacts (Considine 2010a). There are also several byproducts of processed gas such as ethane, propane, butanes that can be used as raw materials and/or final products by other local industries. Higginbotham (2010) further identified a non-quantifiable economic impact of the natural gas industry as the community partnerships that many companies have with local schools, service departments, associations, clubs and charitable organizations.

IMPLAN was also used to estimate income generated from developing Marcellus shale on the GWNF. Labor income is employee compensation (value of all wages and benefits) plus the income to sole proprietorships. The average annual labor income for the first decade for each resource program expenditure is given by alternative in Table 3D-31. Impacts to the local economy industries are shown in Table 3D-32. For more information on the definition of the industrial sectors, see the Economic Affected Environment section in Chapter 3, Section C12. As with employment, the development of natural gas has by far the greatest impact on labor income than any other resource activity on GWNF lands.

Table 3D-31. Labor Income by Program by Alternative (Average Annual, Decade 1, thousands of 2012 dollars), with Marcellus Shale Gas Development

Resource	Alt A	Alt B	Alt C	Alt D	Alt E	Alt F	Alt G	Alt H	Alt I
Recreation	$2,030	$2,061	$1,754	$2,173	$1,945	$2,169	$2,104	$2,105	$2,105
Wildlife and Fish	$1,417	$1,439	$1,204	$1,515	$1,351	$1,512	$1,468	$1,468	$1,468
Timber	$2,426	$3,011	$0	$5,845	$1,674	$1,049	$3,011	$3,114	$3,114
Minerals	$90,163	$68,962	$16,031	$68,962	$23,941	$56,525	$24,033	$53,900	$16,031
Payments to States/Counties	$2,593	$2,593	$2,593	$2,593	$2,593	$2,593	$2,593	$2,593	$2,593
Forest Service Expenditures	$16,544	$12,058	$8,794	$13,608	$11,540	$11,010	$12,123	$12,126	$12,126
Total Forest Management	$115,173	$90,124	$30,376	$94,696	$43,043	$74,857	$45,332	$75,307	$37,437

Table 3D-32. Labor Income by Major Industry by Alternative (Average Annual, Decade 1, thousands of 2012 dollars), with Marcellus Shale Gas Development

Industry	Alt A	Alt B	Alt C	Alt D	Alt E	Alt F	Alt G	Alt H	Alt I
Agriculture	$1,694	$1,953	$84	$3,298	$1,147	$786	$1,946	$1,989	$1,989
Mining	$68,601	$52,561	$12,182	$52,561	$18,333	$43,079	$18,401	$41,037	$12,182
Utilities	$649	$510	$184	$539	$246	$427	$258	$431	$227
Construction	$3,640	$2,746	$794	$2,771	$1,006	$2,278	$1,022	$2,228	$926
Manufacturing	$873	$969	$173	$1,860	$508	$509	$787	$950	$894
Wholesale Trade	$1,640	$1,381	$648	$1,478	$844	$1,217	$907	$1,225	$1,211
Transportation & Warehousing	$1,650	$1,370	$529	$1,490	$746	$1,155	$806	$1,176	$591
Retail Trade	$3,858	$3,162	$1,525	$3,334	$1,944	$2,806	$2,064	$2,813	$1,855
Information	$417	$336	$132	$351	$172	$286	$180	$285	$156
Finance & Insurance	$1,770	$1,405	$488	$1,467	$670	$1,174	$702	$1,172	$523
Real Estate & Rental & Leasing	$724	$576	$222	$598	$292	$488	$303	$486	$254
Prof, Scientific, & Tech Services	$3,349	$2,575	$850	$2,640	$1,140	$2,155	$1,173	$2,127	$993
Mngt of Companies	$851	$656	$171	$668	$244	$539	$250	$524	$199
Admin, Waste Mngt & Rem Services	$890	$719	$283	$754	$370	$610	$387	$610	$302
Educational Services	$457	$358	$123	$376	$172	$298	$181	$300	$159
Health Care & Social Assistance	$4,085	$3,197	$1,126	$3,364	$1,578	$2,666	$1,661	$2,689	$1,377
Arts, Entertainment, and Recreation	$464	$423	$276	$445	$324	$409	$348	$402	$325
Accommodation & Food Services	$1,906	$1,665	$980	$1,756	$1,182	$1,556	$1,265	$1,543	$1,144
Other Services	$1,790	$1,420	$487	$1,506	$684	$1,174	$728	$1,193	$562
Government	$15,866	$12,142	$9,118	$13,441	$11,441	$11,245	$11,963	$12,128	$10,694
Total Forest Mgt	$115,173	$90,124	$30,376	$94,696	$43,043	$74,857	$45,332	$75,307	$36,563

FEDERAL ROYALTIES AND STATE TAXES

Under the Mineral Leasing Act of 1920, royalties are paid to the federal government for oil and gas production from public lands. Royalties are paid at 12.5 percent of production value. This would result in the following royalties under each alternative. From the federal mineral royalties, 25% are returned to the state where the activity occurred. Additional outputs would occur as federal revenue from bonus bids, annual lease rentals, and State and counties 25% share of these federal revenues. Other outputs include severance tax revenue to state or counties and *Ad valorem* property taxes on production and field equipment.

Table 3D-33. Federal Royalties from Marcellus Shale Development by Alternative (million $)

	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Federal revenue production royalty	$365	$282	$0	$282	$21	$210	$21	$177

Virginia has a severance tax that returns 3% to the producing county. West Virginia has a 5% severance tax. Assuming that development on private lands would occur with development on GWNF lands, there would also be increases in real property taxes, personal property taxes, sales and use taxes, corporation income taxes, permits, bonds and other environmental taxes or fees. The Virginia Oil and Gas Association reports that the production of conventional natural gas and coalbed methane, occurring almost exclusively in the southwest region of the state, resulted in 102.9 billion cubic feet of gas in 2006, with about $16,000,000 paid to those counties from severance taxes.

ECONOMIC EFFICIENCY

Present net value (PNV) is the measure used to calculate economic efficiency and highlights the differences among alternatives in the long-term value of management activities. Table 3D-34 represents the PNV from other resource outputs as described in Chapter 3, Section C Table 3C12-24, plus development of Marcellus shale gas on federal and private leases within the GWNF.

Table 3D-34. Cumulative Decadal Present Net Values of Benefits and Costs with Development of Marcellus Shale (millions of dollars, 4% discount rate cumulative to midpoint of 5th decade)

Program	Alt A	Alt B	Alt C	Alt D	Alt E	Alt F	Alt G	Alt H	Alt I
Present Value Benefits by Program:									
Range	<$1	<$1	<$1	<$1	<$1	<$1	<$1	<$1	<$1
Timber	$36	$71	$0	$145	$36	$21	$62	$67	$67
Minerals	$23,826	$18,992	$4,230	$18,992	$5,389	$15,256	$5,421	$13,808	$4,230
Recreation	$1,162	$1,181	$1,007	$1,242	$1,111	$1,244	$1,205	$1,206	$1,206
Wildlife	$661	$668	$562	$713	$640	$698	$684	$684	$684
Total Present Value Benefits	$25,685	$20,912	$5,799	$21,093	$7,177	$17,220	$7,373	$15,765	$6,187
Present Value Costs by Program:									
Range	<$1	<$1	<$1	<$1	<$1	<$1	<$1	<$1	<$1
Timber	$55	$69	$0	$106	$47	$36	$69	$69	$69
Roads/Engineering	$73	$46	$43	$48	$46	$45	$46	$46	$46
Minerals	$5	$5	$4	$6	$5	$5	$5	$5	$5
Recreation	$151	$91	$99	$107	$91	$97	$93	$93	$93
Wildlife	$38	$16	$10	$17	$16	$16	$16	$16	$16
Soil, Water and Air	$38	$18	$19	$17	$18	$18	$18	$18	$18
Protection/Forest Health	$27	$49	$32	$38	$55	$50	$49	$49	$49
Lands	$37	$11	$11	$10	$11	$11	$11	$11	$11
Planning, Inventory, Monitoring	$9	$10	$11	$10	$12	$10	$10	$10	$10
Total Present Value Costs	$433	$315	$230	$356	$302	$288	$317	$317	$317
Cumulative Total Present Net Value	$25,252	$20,597	$5,569	$20,737	$6,875	$16,932	$7,056	$15,448	$5,870

SUMMARY OF DIRECT AND INDIRECT SOCIAL AND ECONOMIC EFFECTS

Natural gas development would provide jobs, increase economic investments and outputs, and increase federal receipts to the United States Treasury and to the local states and counties. It could also stress community services and infrastructure, as well as affect the quality of life and landscape character of a community or region. Potential changes can be viewed as being either positive or negative. For example, in a study of Pennsylvania residents, Alter and others (2010) concluded that most described the development of the Marcellus shale in their area as a chance for 'economic revival', but raised concerns about the potential costs to various segments of the community, infrastructure and the natural environment. For some residents, the industry could bring jobs, capital investments and increased income but for others, it could bring threats of social upheaval and possible environmental problems, declining social well-being and a decreased quality of life. However, most participants in their study were hopeful that communities could develop strategies and tools for managing growth, generating taxes for local jurisdictions, and developing training programs for entry level gas industry jobs.

As mentioned previously, the pace and scale of drilling is the most critical determinant in the magnitude of social and economic impacts to a region. Table 3D-35 provides a comparison of the possible pace and scale of development reflected in each of the nine FEIS alternatives and the Reasonably Foreseeable Development (RFD) Scenario on GWNF lands over the next 15 years. Common to all alternatives are development of: 1)

private mineral rights on GWNF lands; and 2) existing federal oil and gas leases. The potential of federal oil and gas activity on federal mineral ownership will vary by alternative.

Table 3D-35. Activities Associated with Gas Well Development for Each Alternative and the Reasonably Foreseeable Development Scenario (includes existing federal leases and private mineral rights).

Activity	Baseline RFD	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Exploration/Evaluation Wells (vertical)	20	19	16	3	16	14	12	14	11
Development Wells (vertical)	50	48	39	9	39	35	30	36	28
Development Wells (horizontal)	249	240	195	42	195	42	156	42	138
Total Wells	319	307	250	54	249	92	198	93	177
New Roads (miles)	246	237	120	42	119	32	47	32	42
Well Pads (acres)	621	597	486	106	486	183	386	185	344

Alternatives C and I represents the lowest amount of development, with gas production only occurring on existing federal leases and on GWNF lands that are under private mineral rights. Alternatives E and G do not allow high-volume hydraulic fracturing (HVHF) which greatly reduces the labor, capital investments and natural gas production associated with natural gas drilling; resulting in fewer local jobs and less flow of money through local economies as compared to the alternatives that allow HVHF. Without the need to transport large amounts of water for HVHF, maintenance costs for roads and truck traffic would be greatly reduced. Given the large amount of federal land where the wells associated with Alternatives E and G could be located and the fact that these wells would be drilled over a 15 year time period, the economic and social impacts should be temporary, short-term and minor. The next highest number of wells occurs with Alternatives F and H, where some HVHF would be allowed. However, in Alternative H, these wells would be located on a more concentrated base of administratively available lands so there could be a higher chance of localized impacts. In Alternative H, road construction would be more restrictive so the amount of new roads is comparable to Alternatives E and G but truck traffic and truck weight on those roads and local roads would be increased with HVHF. Given the 15 year time period for less than 200 wells associated with Alternatives F and H, it is likely that impacts would be short-term since permanent gas jobs and creation of new local businesses to support the gas industry would probably not be needed. Yet, if development should occur concurrently on adjacent private lands, there could begin to be cumulative impacts. The remaining alternatives (A, B, and D) would have larger social and economic impacts due to the increased amount of wells, especially horizontal wells, and the amount of road construction.

CUMULATIVE SOCIAL AND ECONOMIC EFFECTS

The Marcellus Shale Play within the Appalachian Basin Province is large and geologically complex, found in parts of Alabama, Georgia, Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. The play as a whole is likely to have natural gas drilling and production over an extended period of time. According to a recent U.S. Department of Energy (DOE) report (NETL 2010), the pace of drilling for Marcellus Shale gas wells is expected to triple by 2020, increasing to approximately 30 trillion cubic feet of shale gas, worth more than $200 billion.

With the high investment in the labor and capital resources needed to drill, any natural gas development on GWNF lands would likely also occur with development on private lands. Cumulative effects would include the potential for development on privately owned lands as well as GWNF lands. However, the magnitude of these

effects depend on the pace and scale of development. Effects from minor levels of development would likely be primarily beneficial from the flow of outside spending into the local economy but the benefits would only be for the short-term. With increased development, indirect changes would take the form of increased business for local merchants and professionals (which would also increase the demand for labor), and possibly increased local population if development activities induce people to relocate permanently to the area. Increases in local personal income could result, as well as changes in demand for housing, schools, and public services. The issue is one of capacity and capability of local communities to absorb and accommodate changes in population and requirements for public and private goods and services and whether the area's communities could accommodate inflows of human and material resources that could result from the leases. However, too much development could change the character of the landscape from rural to more of an industrial nature, which could affect retention of residents or tourism attractiveness.

Large projects in close proximity to population centers could affect local communities more profoundly than self-contained, small-scale projects located far from local communities. Projects that encourage large-scale movement of people into an area for short time periods may also present serious challenges to local communities.

An example is provided by Kelsey and others (2012) who reported the local community economic effects for just Bradford County, Pennsylvania. Bradford County is the leading county in the number of Marcellus shale wells in Pennsylvania, with 513 wells drilled between 2008 and 2010 and 1,747 drilling permits issued. Despite the height of activity occurring within the county, they found that the county level employment and income increases suggest that much of the money and jobs are being generated elsewhere due to a small local economy that cannot offer those resources locally. Kelsey found that many of the companies involved in the drilling were regional, national or even international and were bringing in specialized equipment and supplies not directly available from local county-based businesses. Drilling rigs, pipeline and fracing sand were not coming from local sources. However, some were establishing regional offices or facilities within the Marcellus region. Services and supplies that were being purchased locally included aggregate for road and well pad construction, local construction and trucking services, motel rooms and other housing, and food services. An earlier study by Kelsey and others (2011) found that one-third of businesses in Bradford County had sales increased due to Marcellus production and local investments have been made in rails, roads, and hotels. Local nonprofits were reporting major charitable giving by gas companies. They found that according to the US Bureau of Labor Statistics, Bradford County had an increase of more than 1,600 jobs from 2009 to 2010 (total county population in 2010 was 63,000), which is a sharp increase over statewide employment trends. That increase included more than 500 mining jobs, 300 construction jobs, and 140 jobs in the accommodation and food service sector.

Roads System Management

Development of oil and gas resources would require access to the well pads and other facilities. Some of this access would be along existing roads and some would require the construction of new roads. Use of existing roads would likely result in additional maintenance needs which would be funded by the developer. Road construction needs are based on Table 3D-6 and summarized below.

Table 3D-36. Oil and Gas Leasing Road Construction by Alternative (includes federal and private leasing activity)

Activity	Alt A	Alt B	Alts C and I	Alt D	Alt E	Alt F	Alt G	Alt H
Roads (miles)	237	120	42	119	32	47	32	42

It is expected that most roads would only be used to access the drilling activity and would be closed to public use. However, each road would be evaluated at the time of design to determine if it would improve access to other management activities and be managed for other purposes.

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