INFORMATION SHEET

PRESIDING: Commissioner Clodfelter, Presiding; Chair Mitchell and Commissioners Brown-Bland, Dockham, Patterson, and Gray
PLACE: Dobbs Building, Room 2115, Raleigh, NC
DATE: Tuesday, June 11, 2019
TIME: 9:54 a.m. to 9:58 a.m.
DOCKET NO.: E-7, Sub 1191
VOLUME NUMBER:
COMPANIES: Duke Energy Carolinas, LLC
DESCRIPTION: Application of Duke Energy Carolinas, LLC, for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Recovery Rider Pursuant to N.C.G.S. § 62-133.8 and NCUC Rule R8-67

APPEARANCES

Please see attached.

WITNESSES

Please see attached.

EXHIBITS

Please see attached.

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DATE FILED: June 28, 2019

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, June 11, 2019

TIME: 9:54 a.m. - 9:58 a.m.

DOCKET NO: E-7, Sub 1191

BEFORE: Commissioner Daniel G. Clodfelter, Presiding
Chair Charlotte A. Mitchell
Commissioner ToNola D. Brown-Bland
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Lyons Gray

IN THE MATTER OF:

Application of Duke Energy Carolinas, LLC, for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Recovery Rider Pursuant to N.C.G.S. § 62-133.8 and NCUC Rule R8-67

A P P E A R A N C E S:

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T A B L E   O F   C O N T E N T S

E X H I B I T S

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1191

In the Matter of: Application of Duke Energy Carolinas, LLC for Approval of Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance Report and Cost Recovery Rider Pursuant to N.C. Gen. Stat. § 62-133.8 and Commission Rule R8-67	))))))))	**APPLICATION FOR APPROVAL OF REPS COST RECOVERY RIDER AND 2018 REPS COMPLIANCE REPORT**

Duke Energy Carolinas, LLC ("DEC" or the "Company"), pursuant to N.C. Gen. Stat. § 62-133.8 and Rule R8-67 of the Rules and Regulations of the North Carolina Utilities Commission ("Commission"), hereby makes this Application (1) for approval of its 2018 Renewable Energy Portfolio Standard ("REPS") Compliance Report, and (2) to implement a monthly charge to recover the incremental costs associated with compliance with the REPS. In support of this Application, the Company respectfully shows the following:

1. The Company is a public utility operating in the states of North Carolina and South Carolina where it is engaged in the generation, transmission, distribution, and sale of electricity for compensation. Its general offices are located at 550 South Tryon Street, Charlotte, North Carolina, and its mailing address is DEC 45A, 550 South Tryon Street, Charlotte, North Carolina 28202.

2. The attorneys for the Company, to whom all communications and pleadings should be addressed, are:

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3. N.C. Gen. Stat. § 62-133.8 requires North Carolina's electric power suppliers to supply ten (10) percent of their North Carolina retail kilowatt hours ("kWh") sales from "renewable energy resources," as that term is defined by N.C. Gen. Stat. § 62-133.8(a)(8), for calendar year 2018. In addition, N.C. Gen. Stat. § 62-133.8(d) requires that the electric power suppliers supply 0.20 percent of their North Carolina retail kWh sales from solar photovoltaic or thermal solar resources in 2018. Further, N.C. Gen. Stat. § 62-133.8(e) and (f) require that the electric power suppliers also obtain their allocated share of the state-wide requirement of 0.20 percent of the total North Carolina retail kWh sold from swine waste resources and 900,000 megawatt hours ("MWh") of the total electric power sold to North Carolina retail customers from poultry waste resources, respectively, in 2018.[1]

4. N.C. Gen. Stat. § 62-133.8(h) provides that the electric public utilities shall be allowed to recover the incremental costs[2] associated with complying with N.C.

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[1] Both the Poultry Waste and Swine Waste Set-Aside Requirements established by N.C. Gen. Stat. § 62-133.8 have been modified by Commission order pursuant to N.C. Gen. Stat. § 62-133.8(i)(2), as discussed herein.

[2] "Incremental costs" include (1) all reasonable and prudent costs incurred by an electric utility to meet the solar and renewable generation requirements of the statute that are in excess of the utility's avoided costs, (2) costs associated with research that encourages the development of renewable energy, energy efficiency, or improved air quality provided those research costs do not exceed one million dollars ($1,000,000) per year, and (3) costs, including program costs, incurred to provide incentives to customers pursuant to N.C.Gen. Stat. § 62-155(f) (solar rebate program costs and incentives).

Gen. Stat. § 62-133.8 through an annual rider not to exceed the following per-account charges:

Customer Class	2008-2011	2012-2014	2015 and thereafter
Residential per account	$ 10.00	$ 12.00	$ 27.00
Commercial per account	$ 50.00	$ 150.00	$ 150.00
Industrial per account	$ 500.00	$ 1,000.00	$1,000.00

The statute provides that the Commission shall ensure that the incremental costs to be recovered from individual customers on a per-account basis are in the same proportion as the per-account annual charges for each customer class set out in the chart above.

5. Rule R8-67(c) requires the Commission to conduct an annual proceeding for each electric public utility to review the utility's costs to comply with N.C. Gen. Stat. § 62-133.8 and establish the electric public utility's annual rider to recover such costs in a timely manner. The Commission shall also establish an experience modification factor ("EMF") to collect the difference between the electric public utility's actual reasonable and prudent REPS costs incurred during the test period and the actual revenues realized during the test period. Rule R8-67(c) further provides that the Commission shall consider each electric public utility's REPS compliance report at the hearing provided for in Rule R8-67(e) and shall determine whether the electric public utility has complied with N.C. Gen. Stat. § 62-133.8(b), (d), (e) and (f).

6. According to Rules R8-67(c) and (e), the electric public utility is to file its application for recovery of its REPS costs, as well as its REPS compliance report, at the same time it files the information required by Rule R8-55, and the Commission is to conduct an annual rider hearing as soon as practicable after the hearing required by Rule R8-55.

7. Pursuant to the provisions of N.C. Gen. Stat. § 62-133.8 and Commission Rule R8-67(e), DEC requests the Commission to establish a rider to recover its reasonable and prudent forecasted REPS compliance costs to be incurred during the rate period. As provided in Rule R8-67(e), the Company requests to return to DEC's retail customers, through the EMF, $1,956,331of REPS costs incurred and other credits for the period beginning January 1, 2018 through December 31, 2018 ("EMF Period") and collect from DEC's retail customers $34,984,948__ for REPS costs to be incurred during the rate period from September 1, 2019 through August 31, 2020 ("Billing Period"). The REPS rider and EMF will be in effect for the twelve-month period September 1, 2019 through August 31, 2020.

8. Pursuant to the provisions of N.C. Gen. Stat. § 62-133.8 and Rule R8-67, DEC requests Commission approval of the annual billing statements, including both the REPS monthly charge and the EMF monthly charge, for each customer class as follows:

Customer Class	**REPS Monthly Charge** (excl. regulatory fee)	**Monthly EMF** (excl. regulatory fee)	**Total REPS Monthly Charge** (excl. regulatory fee)	**Total REPS Monthly Charge** (incl. regulatory fee)
Residential	$ 0.94	$ (0.07)	$ 0.87	$ 0.87
General[3]	$ 4.82	$ (0.18)	$ 4.64	$ 4.65
Industrial	$20.53	$ 0.75	$21.28	$21.31

The calculation of these rates is set forth in Exhibit No. 4 of the direct testimony of Veronica I. Williams filed with this Application.

[3] Duke Energy Carolinas' General Service rate schedule generally covers the class of customers intended to be captured by the "Commercial" class included within N.C. Gen. Stat. § 62-133.8. The Company does not have a rate schedule for "Commercial" customers.

9. Further, pursuant to the provisions of N.C. Gen. Stat. § 62-133.8 and Commission Rule R8-67(c), the Company requests Commission approval of its 2018 REPS Compliance Report, attached as an exhibit to the direct testimony of Megan Jennings filed in support of this Application. As described by Ms. Jennings' testimony, and illustrated in DEC's 2018 REPS Compliance Report, the Company has complied with the requirements of N.C. Gen. Stat. § 62-133.8(b) and (d) for 2018. In its October 8, 2018 *Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief*, in Docket No. E-100, Sub 113, the Commission lowered the 2018 Poultry Waste Set-Aside Requirement (N.C. Gen. Stat. § 62-133.8(f)) to 300,000 MWh and delayed by one year the scheduled increases in that requirement. The Commission also lowered the Swine Waste Set-Aside Requirement for DEC, Duke Energy Progress, LLC and Dominion Energy North Carolina to 0.02% of prior-year retail sales, delaying the scheduled increase to 0.07% of prior-year retail sales to begin in calendar year 2019, and delaying future increases by one year.[4] The Company has complied with these modified Poultry Waste and Swine Waste Set-Aside Requirements.

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[4] In its *Order Modifying the Poultry and Swine Waste Set-Aside and Granting Other Relief* issued in Docket No. E-100, Sub 113 (November 29, 2012), the Commission eliminated the Swine Waste Set-Aside Requirement for 2012 and delayed for one year the Poultry Waste Set-Aside Requirement. In its March 26, 2014, *Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief*, the Commission delayed the Swine and Poultry Waste Set-Aside Requirements for an additional year. In its November 13, 2014 *Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief*, the Commission directed that Swine Waste Set-Aside Requirement remain at 0.07 percent for the years 2015-2016. Subsequently, in its December 1, 2015 *Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief*, the Commission directed that the Swine Waste Set-Aside Requirement for 2015 be delayed an additional year and that the 2015 Poultry Waste Set-Aside Requirement would be the same as the 2014 level. In its October 17, 2016 *Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief*, the Commission directed that the 2016 Swine Waste Set-Aside Requirement be delayed an additional year and that the 2016 Poultry Waste Set-Aside Requirement remain at the same level as the 2015 requirement and delayed by one year the scheduled increases in that requirement. In its October 16, 2017 *Order Modifying the Swine and Poultry*

10. The information and data required to be filed under Commission Rule R8-67 is contained in the direct testimony and exhibits of Witnesses Jennings and Williams, which are being filed simultaneously with this Application and incorporated herein by reference.

WHEREFORE, the Company respectfully prays:

That consistent with this Application, the Commission approves the Company's 2018 REPS Compliance Report and allows the Company to implement the rate riders as set forth above.

Waste Set-Aside Requirements and Providing Other Relief, in Docket No. E-100, Sub 113, the Commission directed that the 2017 Swine Waste Set-Aside Requirement be delayed an additional year and that the 2017 Poultry Waste Set-Aside Requirement (N.C. Gen. Stat. § 62-133.8(f)) remain at the same level as the 2016 requirement, which the Commission had previously approved at 170,000 MWh, and delayed by one year the scheduled increases in that requirement. In its October 8, 2018 *Order Modifying the Swine and Poultry Waste Set-Aside Requirements And Providing Other Relief* in Docket No. E-100, Sub 113, the Commission modified the 2018 Swine Waste Set-Aside Requirement for electric public utilities to 0.02% and delayed by one year the scheduled increases to the requirement. The Commission also modified the 2018 Poultry Waste Set-Aside Requirement to 300,000 MWh, and delayed by one year the scheduled increases in the requirement.

Respectfully submitted, this the 26th day of February, 2019.

Robert W. Kaylor

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ATTORNEYS FOR DUKE ENERGY CAROLINAS, LLC

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	DOCKET NO. E-7, SUB 1191
COUNTY OF MECKLENBURG	)	

Veronica I. Williams, being first duly sworn, deposes and says:

That she is Rates and Regulatory Strategy Manager for Duke Energy Carolinas, LLC; that she has read the foregoing Application and knows the contents thereof; that the same is true except as to those matters stated on information and belief; and as to those matters, she believes them to be true.

Veronica I. Williams

Sworn to and subscribed before me
this the 22nd day of February, 2019.

Notary Public Aloma M. Felder

My Commission Expires: July 21, 2021

ALOMA M. FELDER
NOTARY
PUBLIC
CABARRUS COUNTY, N.C.

I/A

JENNINGS EXHIBIT NO. 1
*****REDACTED VERSION*****

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1191

In the Matter of	)	
	)	DUKE ENERGY CAROLINAS,
Application of Duke Energy Carolinas, LLC for	)	LLC 2018 RENEWABLE
Approval of Renewable Energy and Energy	)	ENERGY & ENERGY
Efficiency Portfolio Standard (REPS)	)	EFFICIENCY PORTFOLIO
Compliance Report and Cost Recovery Rider	)	STANDARD COMPLIANCE
Pursuant to N.C. Gen. Stat. § 62-133.8 and	)	REPORT
Commission Rule R8-67	)	

DUKE ENERGY CAROLINAS, LLC
RENEWABLE ENERGY AND ENERGY EFFICIENCY
PORTFOLIO STANDARD ("REPS")
COMPLIANCE REPORT

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(A) INTRODUCTION

Duke Energy Carolinas, LLC ("Duke Energy Carolinas," "DEC," or the "Company") submits its Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Compliance Report ("Compliance Report") in accordance with N.C. Gen. Stat. § 62-133.8 and Commission Rule R8-67(c). This Compliance Report provides the required information for 2018 calendar year reporting period.[1] As part of its REPS Compliance Plan, filed in Docket No. E-100, Sub 157, Duke Energy Carolinas plans to provide services to native load priority wholesale customers that contract with the Company for services to meet the REPS requirements, including delivery of renewable energy resources and compliance planning and reporting. These native load priority wholesale customers – including distribution cooperatives and municipalities – may rely on Duke Energy Carolinas to provide this renewable energy delivery service in accordance with N.C. Gen. Stat. § 62-133.8(c)(2)e.

This Compliance Report provides the required information in aggregate for the Company and the following wholesale customers for whom the Company provided renewable energy resources and compliance reporting services: Blue Ridge Electric Membership Corporation, Rutherford Electric Membership Corporation, City of Concord, Town of Dallas, Town of Forest City, Town of Highlands, and City of Kings Mountain ("Wholesale")[2].

(B) REPS COMPLIANCE REPORT

I. RENEWABLE ENERGY CERTIFICATES

The table below reflects the renewable energy certificates ("RECs") used to comply with N.C. Gen. Stat. § 62-133.8(d) for the year 2018.

[BEGIN CONFIDENTIAL]

[redacted]	[redacted]	[redacted]
[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[1] Pursuant to NCUC Rule R8-67(c)(1), this Compliance Report reflects Duke Energy Carolinas' efforts to meet the REPS requirements for the previous calendar year.

[2] The Company's contractual obligation to provide REPS compliance services to the City of Concord and City of Kings Mountain ends effective December 31, 2018. Information provided within this Compliance Report for REPS reporting year 2018 includes City of Concord and City of Kings Mountain.

[redacted]

Totals may not foot due to rounding.

[END CONFIDENTIAL]

II. ACTUAL 2018 TOTAL NORTH CAROLINA RETAIL SALES AND YEAR-END NUMBER OF ACCOUNTS, BY CUSTOMER CLASS

North Carolina Retail Sales (MWh)	2018
Duke Energy Carolinas	59,480,703
Wholesale	3,799,058
Total MWh Sales	**63,279,761**

2018 Year-end Number of REPS Accounts			
Account Type	Duke Energy Carolinas	Wholesale	Total
Residential	1,732,150	164,935	1,897,085
General	247,163	19,752	266,915
Industrial	4,771	274	5,045

III. AVOIDED COST RATES

The avoided cost rates below, applicable to energy received pursuant to power purchase agreements, represent the annualized avoided cost rates in Schedule PP or PP-N (NC), Distribution Interconnection, approved in the following avoided cost proceedings:

ANNUALIZED TOTAL CAPACITY AND ENERGY RATES (CENTS PER KWH)						
Docket No.:	E-100 Sub 148 (Current)	E-100, Sub 140	E-100, Sub 136	E-100, Sub 127	E-100, Sub 117	E-100, Sub 106
Year filed:	2016	2014	2012	2010	2008	2006
Variable Rate	3.26	4.32	4.98	5.48	6.4	5.4
5 Year	N/A	4.52	5.19	5.63	6.39	5.46
10 Year	3.86	5.15	5.52	6.28	6.42	5.51
15 Year	N/A	5.62	5.84	6.63	6.56	5.64

IV. ACTUAL TOTAL AND INCREMENTAL COSTS INCURRED IN 2018

Actual costs incurred in 2018 for REPS compliance were comprised of the following cost of energy purchases and the purchase of various types of RECs, solar distributed generation at Duke Energy Carolinas-owned facilities, and other reasonable and prudent costs incurred to meet the requirements of the statute.

Actual Costs Incurred	Energy and REC Costs	Other	Total Costs
Total costs incurred	$97,682,102	$2,104,766	$99,786,868
Avoided costs	$71,522,732	$0	$71,522,732
Incremental costs	$26,159,370	$2,104,766	$28,264,136

V. ACTUAL INCREMENTAL COSTS COMPARISON TO THE ANNUAL COST CAP AS OF THE PREVIOUS CALENDAR YEAR

Account Type	Total 2017 Year-end number of Retail Accounts[1]	Annual Per-Account Cost Cap	Total Annual Cost Cap
Residential	1,867,227	$27	$50,415,129
General	263,118	$150	$39,467,700
Industrial	5,093	$1000	$5,093,000
	Total Annual Cost Cap		**$94,975,829**
	Actual Incremental Costs		**$28,264,136**

VI. STATUS OF COMPLIANCE WITH REPS REQUIREMENTS

Pursuant to N.C. Gen. Stat. § 62-133.8(b) for Duke Energy Carolinas retail and N.C. Gen. Stat. § 62-133.8(c) for the Company's Wholesale REPS customers, the REPS requirement for calendar year 2018 is set at 10% of 2017 North Carolina ("NC") retail sales. To comply with the combined REPS obligation for Duke Energy Carolinas Retail and its Wholesale REPS customers, the Company submitted 5,923,670 RECs for retirement, including 14,084 Senate Bill 886 ("SB886") RECs, each of which counts for two poultry waste and one general requirement REC. Accordingly, the Company submitted for retirement the equivalent of 5,951,838 RECs, representing 10% of combined 2017 retail megawatt-hour sales of 59,518,351. Details of the composition of RECs retired to meet the total REPS compliance requirement are contained in Section I. of this report.

Pursuant to N.C. Gen. Stat. § 62-133.8(d), for calendar year 2018, at least 0.20% of total NC retail sales (measured according to prior calendar year NC retail sales) shall be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities. As a result, 119,041 solar RECs were submitted for retirement to meet the solar set-aside requirement. 1,899,433 additional solar RECs were submitted for retirement toward compliance with the general requirement (the total REPS requirement net of the solar, poultry, and swine set-aside obligations).

In its October 8, 2018 *Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief* ("2018 Delay Order") in Docket No. E-100, Sub 113, the Commission modified the swine waste set-aside requirement for 2018 to 0.02% of total NC retail sales, and specified that the requirement applies to electric public utilities only, not to electric

[1] Includes number of retail accounts for Duke Energy Carolinas and its Wholesale REPS customers.

membership cooperatives or municipalities (which were excused from the swine waste set-aside requirement for 2018). To comply with the swine waste set-aside requirement applicable to DEC's NC retail sales, the Company submitted for retirement 11,203 swine RECs.

The 2018 Delay Order also reduced the 2018 poultry waste set-aside requirement to 300,000 MWh state-wide, and set the 2019 and 2020 levels at 700,000 MWh and 900,000 MWh, respectively. In its August 5, 2016 *Order Establishing 2016, 2017, and 2018 Poultry Waste Set-Aside Requirement Allocation* in Docket No. E-100, Sub 113, the Commission directed the annual aggregate poultry waste set-aside requirement to be allocated among electric power suppliers and utility compliance aggregators based on the load ratio share calculations shown on the spreadsheet filed by the NC-RETS Administrator in the same docket on July 11, 2016. These percentages were applied to the modified 2018 state-wide requirement to determine the swine waste set-aside requirements applicable to DEC NC retail and to the Company's Wholesale customers for reporting year 2018. The Company submitted for retirement 108,493 poultry waste RECs along with 14,084 SB886 RECs, which count as 28,168 poultry waste set-aside RECs. Accordingly, the Company submitted the equivalent of 136,661 poultry RECs for compliance, and met its 2018 poultry waste set-aside requirement.

VII. IDENTIFICATION OF RECs CARRIED FORWARD

The table below reflects the RECs at year-end 2018 that the Company has banked for use in compliance in future years.

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

VIII. DATES AND AMOUNTS OF ALL PAYMENTS MADE FOR RENEWABLE ENERGY CERTIFICATES

Confidential Appendix 1 provides the dates and amounts of payments made for RECs for calendar year 2018.

(C) METHODOLOGY FOR DETERMINING NUMBER OF CUSTOMERS AND CUSTOMER CAP

In its *Order Approving REPS Riders*, issued in Docket No. E-7, Sub 872 (December 15, 2009), the Commission approved the following method of determining number of customer accounts as proposed by Duke Energy Carolinas. For purposes of defining which accounts will be assessed a REPS charge, and determining account totals by class that will be included in calculating its annual cap on costs incurred to comply with REPS requirements, the Company implemented the method described below. The Company defines "account" as an "agreement," or "tariff rate," between Duke Energy Carolinas and a customer to determine the monthly REPS charge for each account, and to compare the charges per account for a twelve-month period to the applicable annual per-account cost cap established in N.C. Gen. Stat. § 62-133.8(h)(4). The same definition applies when compiling account totals by class, to which the annual per-account caps are applied to determine the overall cap for total annual compliance costs incurred established in N.C. Gen. Stat. § 62-133.8(h)(3). There is a limited number of exceptions to this definition of account. The following service schedules should not be considered accounts for purposes of the per-account charge because of the near certainty that customers served under these schedules already will pay a per-account charge under another residential, general service or industrial service agreement and because they represent small auxiliary service loads. The following agreements fall within this exception[3]:

- Outdoor Lighting Service (Schedule OL)
- Floodlighting Service (Schedule FL and FL-N)
- Street and Public Lighting Service (Schedule PL)
- Yard Lighting (Schedule YL)
- Governmental Lighting (Schedule GL)
- Nonstandard Lighting (Schedule NL)

[3] Lighting service schedules have been updated to reflect the addition of new schedules Governmental Lighting service (Schedule GL) and Nonstandard Lighting service (Schedule NL) and the cancellation of Street Lighting service (Schedule SL) as approved by the Commission on December 7, 2009 in Docket No. E-7, Sub 909, *Order Granting General Rate Increase and Approving Amended Stipulation.*

- Off-Peak Water Heating (Schedule WC is a sub-metered service)
- Non-demand metered, nonresidential service, provided on Schedule SGS, at the same premises, with the same service address, and with the same account name as an agreement for which a monthly REPS charge has been applied.

Within the Wholesale customer group, Blue Ridge Electric Membership Corporation, Rutherford Electric Membership Corporation, Town of Forest City and the City of Concord have proposed a methodology for determining Wholesale year-end number of accounts that is generally consistent with that proposed by Duke Energy Carolinas. The Town of Highlands, Town of Dallas, and City of Kings Mountain propose to define an account in the manner the information is reported to the Energy Information Administration for annual electric sales and revenue reporting.

Respectfully submitted this 26th day of February, 2019.

Robert W. Kaylor

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Counterparty and Payment Dates		REC Cost
[BEGIN CONFIDENTIAL]		
[redacted]		
Apr-2018	$	1,380
Aug-2018	$	1,620
Dec-2018	$	1,000
Feb-2018	$	1,152
Jan-2018	$	920
Jul-2018	$	1,736
Jun-2018	$	1,568
Mar-2018	$	852
May-2018	$	1,564
Nov-2018	$	1,380
Oct-2018	$	1,272
Sep-2018	$	1,684
[redacted]		
Jan-2018	$	34,500
[redacted]		
Apr-2018	$	2,140
Aug-2018	$	2,352
Dec-2018	$	1,484
Feb-2018	$	1,712
Jan-2018	$	1,328
Jul-2018	$	2,484
Jun-2018	$	2,320
Mar-2018	$	1,320
May-2018	$	2,340
Nov-2018	$	2,068
Oct-2018	$	1,808
Sep-2018	$	2,532
[redacted]		
Apr-2018	$	4,280
Aug-2018	$	4,775
Dec-2018	$	2,805
Feb-2018	$	3,075
Jan-2018	$	1,900
Jul-2018	$	5,030
Jun-2018	$	4,675
Mar-2018	$	2,440
May-2018	$	4,705
Nov-2018	$	3,900
Oct-2018	$	3,625
Sep-2018	$	4,865
[redacted]		
Apr-2018	$	4,355
Aug-2018	$	4,895
Dec-2018	$	3,045
Feb-2018	$	3,450
Jan-2018	$	2,585
Jul-2018	$	5,250
Jun-2018	$	4,580
Mar-2018	$	2,550
May-2018	$	4,765
Nov-2018	$	3,455

Counterparty and Payment Dates		REC Cost
Oct-2018	$	3,365
Sep-2018	$	4,925
[redacted]		
Apr-2018	$	2,252
Aug-2018	$	2,224
Dec-2018	$	2,256
Feb-2018	$	1,280
Jan-2018	$	655
Jul-2018	$	2,272
Jun-2018	$	2,272
Mar-2018	$	1,692
May-2018	$	2,272
Nov-2018	$	2,204
Oct-2018	$	1,624
Sep-2018	$	2,268
[redacted]		
Apr-2018	$	4,683
Aug-2018	$	5,872
Dec-2018	$	1,028
Feb-2018	$	2,545
Jan-2018	$	288
Jul-2018	$	23,282
Jun-2018	$	3,615
Mar-2018	$	6,333
May-2018	$	4,048
Nov-2018	$	3,324
Oct-2018	$	3,092
Sep-2018	$	5,372
[redacted]		
Apr-2018	$	1,878
Aug-2018	$	2,200
Dec-2018	$	1,400
Feb-2018	$	1,640
Jan-2018	$	1,190
Jul-2018	$	2,298
Jun-2018	$	2,183
Mar-2018	$	1,095
May-2018	$	2,205
Nov-2018	$	1,908
Oct-2018	$	1,678
Sep-2018	$	2,238
[redacted]		
Apr-2018	$	1,852
Aug-2018	$	1,996
Dec-2018	$	1,204
Feb-2018	$	1,336
Jan-2018	$	948
Jul-2018	$	2,172
Jun-2018	$	2,052
Mar-2018	$	1,076
May-2018	$	2,024
Nov-2018	$	1,716
Oct-2018	$	1,552
Sep-2018	$	1,944

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
[redacted]		
Apr-2018	$	1,716
Aug-2018	$	900
Dec-2018	$	2,092
Feb-2018	$	788
Jan-2018	$	664
Jul-2018	$	1,260
Jun-2018	$	1,952
Mar-2018	$	1,600
May-2018	$	1,736
Nov-2018	$	1,892
Oct-2018	$	1,768
Sep-2018	$	1,516
[redacted]		
Apr-2018	$	-
Aug-2018	$	-
Dec-2018	$	-
Feb-2018	$	-
Jan-2018	$	2,440
Jul-2018	$	-
Jun-2018	$	-
Mar-2018	$	-
May-2018	$	-
Nov-2018	$	-
Oct-2018	$	-
Sep-2018	$	-
[redacted]		
Apr-2018	$	2,628
Aug-2018	$	3,256
Dec-2018	$	1,776
Feb-2018	$	352
Jul-2018	$	3,356
Jun-2018	$	3,100
Mar-2018	$	1,500
May-2018	$	3,108
Nov-2018	$	2,508
Oct-2018	$	2,172
Sep-2018	$	3,176
[redacted]		
Feb-2018	$	188
Jan-2018	$	145
Mar-2018	$	120
[redacted]		
Apr-2018	$	2,520
Aug-2018	$	2,800
Dec-2018	$	1,664
Feb-2018	$	1,944
Jan-2018	$	1,528
Jul-2018	$	2,988
Jun-2018	$	2,648
Mar-2018	$	1,472
May-2018	$	2,524
Nov-2018	$	2,356
Oct-2018	$	2,168

Counterparty and Payment Dates		REC Cost
Sep-2018	$	2,804
[redacted]		
Apr-2018	$	1,663
Aug-2018	$	1,780
Dec-2018	$	1,170
Feb-2018	$	1,338
Jan-2018	$	1,003
Jul-2018	$	1,868
Jun-2018	$	1,748
Mar-2018	$	965
May-2018	$	1,765
Nov-2018	$	1,553
Oct-2018	$	1,363
Sep-2018	$	1,855
[redacted]		
Apr-2018	$	3,840
Aug-2018	$	4,535
Dec-2018	$	2,660
Feb-2018	$	2,565
Jan-2018	$	2,410
Jul-2018	$	3,505
Jun-2018	$	4,595
Mar-2018	$	1,460
May-2018	$	4,625
Nov-2018	$	3,275
Oct-2018	$	3,110
Sep-2018	$	4,740
[redacted]		
Apr-2018	$	2,125
Aug-2018	$	2,500
Dec-2018	$	895
Feb-2018	$	1,405
Jan-2018	$	1,305
Jul-2018	$	2,610
Jun-2018	$	2,610
Mar-2018	$	1,235
May-2018	$	2,590
Nov-2018	$	1,005
Oct-2018	$	1,435
Sep-2018	$	2,495
[redacted]		
Jan-2018	$	41,847
[redacted]		
Apr-2018	$	2,324
Aug-2018	$	2,560
Dec-2018	$	1,516
Feb-2018	$	816
Jan-2018	$	1,260
Jul-2018	$	2,424
Jun-2018	$	2,008
Mar-2018	$	1,336
May-2018	$	2,628
Nov-2018	$	1,940
Oct-2018	$	1,888

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Sep-2018	$	2,604
[redacted]		
Apr-2018	$	69,468
Aug-2018	$	70,568
Dec-2018	$	70,236
Feb-2018	$	62,852
Jan-2018	$	125,528
Jul-2018	$	135,868
Mar-2018	$	73,328
May-2018	$	49,260
Oct-2018	$	26,076
Sep-2018	$	64,560
[redacted]		
Apr-2018	$	2,232
Aug-2018	$	2,904
Dec-2018	$	1,672
Feb-2018	$	1,804
Jan-2018	$	1,408
Jul-2018	$	3,128
Jun-2018	$	2,568
Mar-2018	$	1,276
May-2018	$	2,664
Nov-2018	$	2,116
Oct-2018	$	2,044
Sep-2018	$	2,852
[redacted]		
Apr-2018	$	524
Aug-2018	$	16,301
Dec-2018	$	544
Feb-2018	$	818
Jan-2018	$	1,287
Jul-2018	$	15,243
Jun-2018	$	1,119
Mar-2018	$	690
May-2018	$	724
Nov-2018	$	982
Oct-2018	$	11,204
Sep-2018	$	14,771
[redacted]		
Apr-2018	$	3,320
Aug-2018	$	3,312
Dec-2018	$	2,248
Feb-2018	$	2,644
Jan-2018	$	2,040
Jul-2018	$	3,884
Jun-2018	$	3,628
Mar-2018	$	1,996
May-2018	$	3,448
Nov-2018	$	3,156
Oct-2018	$	2,844
Sep-2018	$	3,744
[redacted]		
Apr-2018	$	2,723
Feb-2018	$	1,443

**Information in italics is confidential*

Counterparty and Payment Dates		REC Cost
Jan-2018	$	1,040
Mar-2018	$	2,250
May-2018	$	1,535
[redacted]		
Apr-2018	$	580
Aug-2018	$	640
Dec-2018	$	244
Feb-2018	$	568
Jan-2018	$	303
Jul-2018	$	384
Jun-2018	$	280
Mar-2018	$	564
May-2018	$	424
Nov-2018	$	240
Oct-2018	$	280
Sep-2018	$	560
[redacted]		
Apr-2018	$	3,224
Aug-2018	$	3,576
Dec-2018	$	1,820
Feb-2018	$	3,172
Jul-2018	$	3,900
Jun-2018	$	3,596
Mar-2018	$	1,648
May-2018	$	3,636
Nov-2018	$	2,732
Oct-2018	$	2,628
Sep-2018	$	3,592
[redacted]		
Apr-2018	$	7,025
Aug-2018	$	7,136
Dec-2018	$	10,168
Feb-2018	$	7,331
Jan-2018	$	7,336
Jul-2018	$	4,980
Jun-2018	$	4,535
Mar-2018	$	6,496
May-2018	$	6,719
Nov-2018	$	10,516
Oct-2018	$	9,862
Sep-2018	$	9,793
[redacted]		
Apr-2018	$	61,251
Aug-2018	$	56,692
Dec-2018	$	59,388
Feb-2018	$	62,555
Jan-2018	$	51,779
Jul-2018	$	61,018
Jun-2018	$	63,034
Mar-2018	$	62,463
May-2018	$	60,364
Nov-2018	$	55,330
Oct-2018	$	49,261
Sep-2018	$	53,662

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
[redacted]		
Sep-2018	$	8,589
[redacted]		
Apr-2018	$	1,312
Aug-2018	$	1,472
Dec-2018	$	900
Feb-2018	$	1,020
Jan-2018	$	772
Jul-2018	$	1,560
Jun-2018	$	1,436
Mar-2018	$	792
May-2018	$	1,440
Nov-2018	$	1,284
Oct-2018	$	1,156
Sep-2018	$	1,524
[redacted]		
Apr-2018	$	154,896
Jul-2018	$	73,948
Jun-2018	$	98,088
Mar-2018	$	99,012
May-2018	$	94,356
Nov-2018	$	77,560
Oct-2018	$	133,328
Sep-2018	$	91,960
[redacted]		
Apr-2018	$	3,920
Aug-2018	$	4,510
Dec-2018	$	2,590
Feb-2018	$	3,175
Jan-2018	$	2,360
Jul-2018	$	4,780
Jun-2018	$	4,515
Mar-2018	$	2,360
May-2018	$	4,465
Nov-2018	$	3,525
Oct-2018	$	2,960
Sep-2018	$	4,510
[redacted]		
Apr-2018	$	18,884
Aug-2018	$	18,702
Dec-2018	$	18,900
Feb-2018	$	16,881
Jan-2018	$	19,347
Jul-2018	$	17,526
Jun-2018	$	17,973
Mar-2018	$	17,179
May-2018	$	18,271
Nov-2018	$	13,919
Oct-2018	$	18,751
Sep-2018	$	19,099
[redacted]		
Apr-2018	$	1,910
Aug-2018	$	2,298
Dec-2018	$	1,360

Counterparty and Payment Dates		REC Cost
Feb-2018	$	1,610
Jan-2018	$	1,215
Jul-2018	$	2,310
Jun-2018	$	2,283
Mar-2018	$	1,098
May-2018	$	2,240
Nov-2018	$	1,385
Oct-2018	$	1,540
Sep-2018	$	2,245
[redacted]		
Apr-2018	$	9,302
Aug-2018	$	10,599
Dec-2018	$	7,230
Feb-2018	$	8,337
Jan-2018	$	6,314
Jul-2018	$	11,928
Jun-2018	$	11,058
Mar-2018	$	5,600
May-2018	$	10,647
Nov-2018	$	9,634
Oct-2018	$	7,989
Sep-2018	$	10,963
[redacted]		
Apr-2018	$	4,105
Aug-2018	$	4,500
Dec-2018	$	2,720
Feb-2018	$	3,115
Jan-2018	$	2,270
Jul-2018	$	4,915
Jun-2018	$	4,540
Mar-2018	$	2,460
May-2018	$	4,535
Nov-2018	$	3,805
Oct-2018	$	3,410
Sep-2018	$	4,715
[redacted]		
Apr-2018	$	4,255
Aug-2018	$	1,665
Dec-2018	$	1,200
Feb-2018	$	1,230
Jan-2018	$	2,810
Jun-2018	$	3,600
Nov-2018	$	1,380
Oct-2018	$	1,550
Sep-2018	$	1,645
[redacted]		
Apr-2018	$	27,868
Aug-2018	$	26,589
Dec-2018	$	26,936
Feb-2018	$	25,462
Jan-2018	$	26,042
Jul-2018	$	26,936
Jun-2018	$	27,001
Mar-2018	$	26,676

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Counterparty and Payment Dates		REC Cost
May-2018	$	28,821
Nov-2018	$	27,434
Oct-2018	$	26,351
Sep-2018	$	28,149
[redacted]		
Apr-2018	$	2,104
Aug-2018	$	2,628
Dec-2018	$	1,332
Feb-2018	$	1,436
Jan-2018	$	1,080
Jul-2018	$	2,664
Jun-2018	$	2,600
Mar-2018	$	1,272
May-2018	$	2,540
Nov-2018	$	1,932
Oct-2018	$	1,732
Sep-2018	$	2,576
[redacted]		
Apr-2018	$	968
Aug-2018	$	1,544
Dec-2018	$	960
Feb-2018	$	840
Jan-2018	$	844
Jul-2018	$	1,240
Jun-2018	$	1,516
Mar-2018	$	920
May-2018	$	1,516
Nov-2018	$	844
Oct-2018	$	1,236
Sep-2018	$	1,344
[redacted]		
Apr-2018	$	4,000
Aug-2018	$	4,165
Dec-2018	$	2,905
Feb-2018	$	3,385
Jan-2018	$	2,735
Jul-2018	$	4,515
Jun-2018	$	4,180
Mar-2018	$	2,480
May-2018	$	4,560
Nov-2018	$	3,455
Oct-2018	$	3,450
Sep-2018	$	4,725
[redacted]		
Apr-2018	$	3,212
Aug-2018	$	3,512
Dec-2018	$	2,060
Feb-2018	$	2,180
Jan-2018	$	1,660
Jul-2018	$	3,408
Jun-2018	$	3,448
Mar-2018	$	1,848
May-2018	$	3,572
Nov-2018	$	2,772

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Counterparty and Payment Dates		REC Cost
Oct-2018	$	2,592
Sep-2018	$	3,560
[redacted]		
Jan-2018	$	23,019
Jun-2018	$	194,970
May-2018	$	14,810
Oct-2018	$	74,310
[redacted]		
Feb-2018	$	7,250
[redacted]		
Apr-2018	$	3,256
Aug-2018	$	3,672
Dec-2018	$	2,336
Feb-2018	$	2,592
Jan-2018	$	2,100
Jul-2018	$	3,684
Jun-2018	$	3,420
Mar-2018	$	1,900
May-2018	$	3,484
Nov-2018	$	3,108
Oct-2018	$	2,932
Sep-2018	$	3,876
[redacted]		
Apr-2018	$	2,240
Aug-2018	$	2,476
Dec-2018	$	1,336
Feb-2018	$	1,444
Jan-2018	$	1,024
Jul-2018	$	2,624
Jun-2018	$	2,436
Mar-2018	$	1,248
May-2018	$	2,524
Nov-2018	$	1,952
Oct-2018	$	1,496
Sep-2018	$	2,316
[redacted]		
Apr-2018	$	1,864
Aug-2018	$	2,308
Dec-2018	$	1,092
Feb-2018	$	1,324
Jan-2018	$	1,020
Jul-2018	$	2,296
Jun-2018	$	2,268
Mar-2018	$	1,112
May-2018	$	2,188
Nov-2018	$	1,716
Oct-2018	$	1,496
Sep-2018	$	2,160
[redacted]		
Apr-2018	$	25,861
Aug-2018	$	25,435
Dec-2018	$	24,887
Feb-2018	$	26,556
Jan-2018	$	24,291

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Jul-2018	$	3,857
Jun-2018	$	12,721
Mar-2018	$	22,741
May-2018	$	23,861
Nov-2018	$	25,840
Oct-2018	$	24,531
Sep-2018	$	25,233
[redacted]		
Apr-2018	$	61,277
Aug-2018	$	62,460
Dec-2018	$	62,105
Feb-2018	$	54,419
Jan-2018	$	40,692
Jul-2018	$	53,449
Jun-2018	$	60,993
Mar-2018	$	60,047
May-2018	$	48,743
Nov-2018	$	61,963
Oct-2018	$	58,841
Sep-2018	$	57,493
[redacted]		
Apr-2018	$	14,661
Aug-2018	$	15,183
Dec-2018	$	11,706
Feb-2018	$	15,739
Jan-2018	$	12,107
Jul-2018	$	10,674
Jun-2018	$	13,305
Mar-2018	$	12,819
May-2018	$	14,557
Nov-2018	$	11,520
Oct-2018	$	10,790
Sep-2018	$	13,630
[redacted]		
Apr-2018	$	3,516
Aug-2018	$	580
Dec-2018	$	3,444
Feb-2018	$	1,468
Jan-2018	$	348
Jul-2018	$	688
Jun-2018	$	2,284
Mar-2018	$	2,512
May-2018	$	2,988
Nov-2018	$	2,044
Oct-2018	$	1,476
Sep-2018	$	2,396
[redacted]		
Apr-2018	$	1,728
Aug-2018	$	1,850
Dec-2018	$	1,107
Feb-2018	$	1,276
Jan-2018	$	884
Jul-2018	$	1,964
Jun-2018	$	1,827

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Mar-2018	$	990
May-2018	$	1,872
Nov-2018	$	1,508
Oct-2018	$	1,341
Sep-2018	$	1,895
[redacted]		
Jan-2018	$	60
[redacted]		
Apr-2018	$	3,216
Aug-2018	$	3,596
Dec-2018	$	2,264
Feb-2018	$	2,644
Jan-2018	$	2,116
Jul-2018	$	3,820
Jun-2018	$	3,660
Mar-2018	$	1,916
May-2018	$	3,600
Nov-2018	$	2,972
Oct-2018	$	2,600
Sep-2018	$	3,636
[redacted]		
Apr-2018	$	2,860
Aug-2018	$	3,784
Dec-2018	$	1,964
Feb-2018	$	2,288
Jan-2018	$	1,624
Jul-2018	$	3,916
Jun-2018	$	3,472
Mar-2018	$	1,668
May-2018	$	3,284
Nov-2018	$	2,576
Oct-2018	$	2,508
Sep-2018	$	3,700
[redacted]		
Apr-2018	$	4,065
Aug-2018	$	4,830
Dec-2018	$	2,895
Feb-2018	$	2,215
Jan-2018	$	2,550
Jul-2018	$	5,160
Jun-2018	$	4,975
Mar-2018	$	2,465
May-2018	$	4,720
Nov-2018	$	4,195
Oct-2018	$	3,960
Sep-2018	$	5,335
[redacted]		
Apr-2018	$	1,565
Aug-2018	$	1,710
Dec-2018	$	1,110
Feb-2018	$	1,275
Jan-2018	$	800
Jul-2018	$	1,835
Jun-2018	$	1,665

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Counterparty and Payment Dates		REC Cost
Mar-2018	$	1,030
May-2018	$	1,780
Nov-2018	$	1,460
Oct-2018	$	1,415
Sep-2018	$	1,700
[redacted]		
Apr-2018	$	1,530
Aug-2018	$	1,670
Dec-2018	$	1,010
Feb-2018	$	1,195
Jan-2018	$	890
Jul-2018	$	1,715
Jun-2018	$	1,585
Mar-2018	$	860
May-2018	$	1,660
Nov-2018	$	1,400
Oct-2018	$	1,285
Sep-2018	$	1,665
[redacted]		
Apr-2018	$	1,256
Aug-2018	$	1,336
Dec-2018	$	852
Feb-2018	$	928
Jan-2018	$	612
Jul-2018	$	1,460
Jun-2018	$	1,320
Mar-2018	$	808
May-2018	$	1,436
Nov-2018	$	1,132
Oct-2018	$	1,092
Sep-2018	$	1,324
[redacted]		
Apr-2018	$	1,384
Aug-2018	$	1,476
Dec-2018	$	932
Feb-2018	$	1,088
Jan-2018	$	840
Jul-2018	$	1,608
Jun-2018	$	1,468
Mar-2018	$	836
May-2018	$	1,488
Nov-2018	$	1,300
Oct-2018	$	1,180
Sep-2018	$	1,560
[redacted]		
Apr-2018	$	1,324
Aug-2018	$	1,564
Dec-2018	$	880
Feb-2018	$	956
Jan-2018	$	736
Jul-2018	$	1,684
Jun-2018	$	1,516
Mar-2018	$	788
May-2018	$	1,520

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Counterparty and Payment Dates		REC Cost
Nov-2018	$	1,272
Oct-2018	$	1,216
Sep-2018	$	1,632
[redacted]		
Apr-2018	$	1,288
Aug-2018	$	1,472
Dec-2018	$	888
Feb-2018	$	1,020
Jan-2018	$	732
Jul-2018	$	1,564
Jun-2018	$	1,448
Mar-2018	$	788
May-2018	$	1,480
Nov-2018	$	1,200
Oct-2018	$	1,088
Sep-2018	$	1,468
[redacted]		
Apr-2018	$	20,723
Jun-2018	$	6,964
May-2018	$	34,814
[redacted]		
Feb-2018	$	51,000
May-2018	$	34,000
[redacted]		
Apr-2018	$	1,468
Aug-2018	$	1,292
Dec-2018	$	1,212
Feb-2018	$	784
Jan-2018	$	740
Jul-2018	$	1,400
Jun-2018	$	1,364
Mar-2018	$	1,240
May-2018	$	1,392
Nov-2018	$	1,312
Oct-2018	$	1,104
Sep-2018	$	1,188
[redacted]		
Sep-2018	$	138
[redacted]		
Apr-2018	$	1,248
Aug-2018	$	1,492
Dec-2018	$	700
Feb-2018	$	724
Jan-2018	$	548
Jul-2018	$	1,604
Jun-2018	$	1,432
Mar-2018	$	696
May-2018	$	1,408
Nov-2018	$	1,100
Oct-2018	$	1,068
Sep-2018	$	1,488
[redacted]		
Apr-2018	$	3,456
Aug-2018	$	3,748

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Counterparty and Payment Dates		REC Cost
Dec-2018	$	2,164
Feb-2018	$	2,736
Jan-2018	$	2,124
Jul-2018	$	4,072
Jun-2018	$	3,708
Mar-2018	$	2,096
May-2018	$	3,744
Nov-2018	$	3,284
Oct-2018	$	3,004
Sep-2018	$	3,972
[redacted]		
Apr-2018	$	11,303
Aug-2018	$	8,397
Dec-2018	$	6,155
Feb-2018	$	8,443
Jan-2018	$	6,433
Jul-2018	$	9,884
Jun-2018	$	10,754
Mar-2018	$	9,976
May-2018	$	9,861
Nov-2018	$	6,086
Oct-2018	$	5,606
Sep-2018	$	7,802
[redacted]		
Apr-2018	$	13,293
Aug-2018	$	8,374
Dec-2018	$	6,498
Feb-2018	$	9,816
Jan-2018	$	7,155
Jul-2018	$	10,937
Jun-2018	$	12,653
Mar-2018	$	11,097
May-2018	$	12,264
Nov-2018	$	4,988
Oct-2018	$	5,148
Sep-2018	$	7,596
[redacted]		
Apr-2018	$	18,768
Aug-2018	$	24,264
Dec-2018	$	22,488
Feb-2018	$	18,000
Jan-2018	$	18,480
Jul-2018	$	19,308
Jun-2018	$	12,564
Mar-2018	$	15,792
May-2018	$	13,452
Nov-2018	$	25,524
Oct-2018	$	24,480
Sep-2018	$	23,904
[redacted]		
Apr-2018	$	14,094
Aug-2018	$	8,603
Dec-2018	$	7,939
Feb-2018	$	8,237

**Information in Italics is confidential*

Counterparty and Payment Dates		REC Cost
Jan-2018	$	7,093
Jul-2018	$	9,427
Jun-2018	$	10,616
Mar-2018	$	11,646
May-2018	$	13,179
Nov-2018	$	8,260
Oct-2018	$	7,733
Sep-2018	$	8,557
[redacted]		
Apr-2018	$	18,530
Aug-2018	$	20,559
Dec-2018	$	17,590
Feb-2018	$	22,192
Jan-2018	$	21,893
Jul-2018	$	22,118
Jun-2018	$	19,347
Mar-2018	$	19,743
May-2018	$	17,417
Nov-2018	$	21,078
Oct-2018	$	23,775
Sep-2018	$	22,711
[redacted]		
Apr-2018	$	3,230
Aug-2018	$	3,920
Dec-2018	$	2,095
Feb-2018	$	2,525
Jan-2018	$	2,045
Jul-2018	$	3,875
Jun-2018	$	3,905
Mar-2018	$	1,930
May-2018	$	3,805
Nov-2018	$	2,140
Oct-2018	$	2,430
Sep-2018	$	3,960
[redacted]		
Apr-2018	$	-
Aug-2018	$	-
Dec-2018	$	-
Feb-2018	$	-
Jan-2018	$	-
Jul-2018	$	-
Jun-2018	$	-
Mar-2018	$	-
May-2018	$	-
Sep-2018	$	-
[redacted]		
Apr-2018	$	1,376
Aug-2018	$	1,628
Dec-2018	$	1,008
Feb-2018	$	1,032
Jan-2018	$	920
Jul-2018	$	1,736
Jun-2018	$	1,572
Mar-2018	$	856

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
May-2018	$	1,556
Nov-2018	$	1,372
Oct-2018	$	1,260
Sep-2018	$	1,652
[redacted]		
Jan-2018	$	180
[redacted]		
Apr-2018	$	3,408
Aug-2018	$	3,652
Dec-2018	$	2,416
Feb-2018	$	2,780
Jan-2018	$	2,200
Jul-2018	$	3,956
Jun-2018	$	3,660
Mar-2018	$	2,036
May-2018	$	3,644
Nov-2018	$	3,168
Oct-2018	$	2,876
Sep-2018	$	3,656
[redacted]		
Apr-2018	$	3,730
Aug-2018	$	4,505
Dec-2018	$	2,480
Feb-2018	$	2,775
Jan-2018	$	2,195
Jul-2018	$	4,665
Jun-2018	$	4,520
Mar-2018	$	2,085
May-2018	$	4,400
Nov-2018	$	3,410
Oct-2018	$	2,990
Sep-2018	$	4,480
[redacted]		
Apr-2018	$	1,654
Aug-2018	$	1,618
Dec-2018	$	1,141
Feb-2018	$	1,370
Jan-2018	$	1,087
Jul-2018	$	1,712
Jun-2018	$	1,872
Mar-2018	$	1,042
May-2018	$	1,766
Nov-2018	$	1,467
Oct-2018	$	1,316
Sep-2018	$	1,724
[redacted]		
Apr-2018	$	1,364
Aug-2018	$	776
Dec-2018	$	2,128
Feb-2018	$	692
Jan-2018	$	672
Jul-2018	$	1,040
Jun-2018	$	1,572
Mar-2018	$	1,236

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
May-2018	$	1,328
Nov-2018	$	1,744
Oct-2018	$	1,512
Sep-2018	$	1,260
[redacted]		
Feb-2018	$	51,000
May-2018	$	34,000
[redacted]		
Dec-2018	$	-
Nov-2018	$	14,813
[redacted]		
Apr-2018	$	3,396
Aug-2018	$	3,928
Dec-2018	$	2,224
Feb-2018	$	2,572
Jan-2018	$	2,056
Jul-2018	$	4,180
Jun-2018	$	3,796
Mar-2018	$	2,004
May-2018	$	3,848
Nov-2018	$	2,604
Oct-2018	$	2,352
Sep-2018	$	4,028
[redacted]		
Feb-2018	$	85,000
[redacted]		
Apr-2018	$	2,824
Aug-2018	$	500
Dec-2018	$	648
Feb-2018	$	988
Jan-2018	$	323
Jul-2018	$	2,328
Jun-2018	$	2,608
Mar-2018	$	1,944
May-2018	$	2,172
[redacted]		
Apr-2018	$	4,120
Aug-2018	$	4,920
Dec-2018	$	2,920
Feb-2018	$	3,260
Jan-2018	$	2,685
Jul-2018	$	5,145
Jun-2018	$	4,945
Mar-2018	$	2,520
May-2018	$	4,750
Nov-2018	$	3,850
Oct-2018	$	3,485
Sep-2018	$	4,920
[redacted]		
Apr-2018	$	1,928
Aug-2018	$	2,332
Dec-2018	$	1,344
Feb-2018	$	1,628
Jan-2018	$	1,272

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Jul-2018	$	2,440
Jun-2018	$	2,360
Mar-2018	$	1,152
May-2018	$	2,280
Nov-2018	$	1,076
Oct-2018	$	1,436
Sep-2018	$	2,304
[redacted]		
Apr-2018	$	1,928
Aug-2018	$	2,336
Dec-2018	$	1,312
Feb-2018	$	1,552
Jan-2018	$	1,224
Jul-2018	$	2,372
Jun-2018	$	2,328
Mar-2018	$	1,164
May-2018	$	2,256
Nov-2018	$	1,556
Oct-2018	$	1,036
Sep-2018	$	1,384
[redacted]		
Apr-2018	$	3,228
Aug-2018	$	2,736
Dec-2018	$	2,204
Feb-2018	$	2,584
Jan-2018	$	2,064
Jul-2018	$	3,696
Jun-2018	$	3,628
Mar-2018	$	1,908
May-2018	$	3,596
Nov-2018	$	2,728
Oct-2018	$	2,672
Sep-2018	$	3,384
[redacted]		
Apr-2018	$	1,998
Aug-2018	$	2,233
Dec-2018	$	1,338
Feb-2018	$	1,660
Jan-2018	$	1,203
Jul-2018	$	2,380
Jun-2018	$	1,933
Mar-2018	$	1,203
May-2018	$	2,210
Nov-2018	$	1,883
Oct-2018	$	1,635
Sep-2018	$	2,345
[redacted]		
Apr-2018	$	3,228
Aug-2018	$	3,724
Dec-2018	$	2,316
Feb-2018	$	2,120
Jan-2018	$	2,196
Jul-2018	$	4,064
Jun-2018	$	3,912

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Mar-2018	$	2,096
May-2018	$	2,424
Nov-2018	$	2,984
Oct-2018	$	2,620
Sep-2018	$	3,728
[redacted]		
Apr-2018	$	1,634
Aug-2018	$	1,949
Dec-2018	$	1,078
Feb-2018	$	1,341
Jan-2018	$	990
Jul-2018	$	1,998
Jun-2018	$	1,924
Mar-2018	$	925
May-2018	$	1,872
Nov-2018	$	1,463
Oct-2018	$	1,303
Sep-2018	$	1,922
[redacted]		
Aug-2018	$	4,689
Dec-2018	$	715
Jul-2018	$	2,265
Nov-2018	$	813
Oct-2018	$	778
Sep-2018	$	1,225
[redacted]		
Nov-2018	$	13,941
[redacted]		
Apr-2018	$	1,104
Aug-2018	$	1,440
Dec-2018	$	984
Feb-2018	$	900
Jan-2018	$	588
Jul-2018	$	1,556
Jun-2018	$	1,384
Mar-2018	$	936
May-2018	$	1,548
Nov-2018	$	1,196
Oct-2018	$	1,420
Sep-2018	$	1,488
[redacted]		
Apr-2018	$	3,715
Aug-2018	$	4,445
Dec-2018	$	2,560
Feb-2018	$	3,020
Jan-2018	$	2,395
Jul-2018	$	4,500
Jun-2018	$	4,395
Mar-2018	$	2,195
May-2018	$	4,350
Nov-2018	$	3,410
Oct-2018	$	3,075
Sep-2018	$	4,430
[redacted]		

**Information in italics is confidential*

Counterparty and Payment Dates		REC Cost
Apr-2018	$	1,644
Aug-2018	$	928
Dec-2018	$	2,012
Feb-2018	$	972
Jan-2018	$	596
Jul-2018	$	1,924
Jun-2018	$	1,768
Mar-2018	$	1,156
May-2018	$	1,668
Nov-2018	$	728
Oct-2018	$	456
Sep-2018	$	1,260
[redacted]		
Apr-2018	$	4,808
Aug-2018	$	4,048
Dec-2018	$	4,728
Feb-2018	$	3,624
Jan-2018	$	2,496
Jul-2018	$	5,320
Jun-2018	$	4,528
Mar-2018	$	5,020
May-2018	$	4,632
Nov-2018	$	3,524
Oct-2018	$	3,336
Sep-2018	$	3,592
[redacted]		
Apr-2018	$	3,468
Aug-2018	$	2,844
Dec-2018	$	4,268
Feb-2018	$	2,192
Jan-2018	$	1,300
Jul-2018	$	5,324
Jun-2018	$	3,692
Mar-2018	$	4,748
May-2018	$	3,112
Nov-2018	$	2,700
Oct-2018	$	2,596
Sep-2018	$	4,572
[redacted]		
Apr-2018	$	5,888
Aug-2018	$	5,516
Dec-2018	$	8,636
Feb-2018	$	4,260
Jan-2018	$	3,104
Jul-2018	$	11,008
Jun-2018	$	8,244
Mar-2018	$	8,716
May-2018	$	5,436
Nov-2018	$	6,752
Oct-2018	$	5,340
Sep-2018	$	6,284
[redacted]		
Dec-2018	$	970,800
May-2018	$	3,686,130

*Information in italices is confidential

Counterparty and Payment Dates		REC Cost
[redacted]		
Dec-2018	$	220
Nov-2018	$	440
Oct-2018	$	406
Sep-2018	$	521
[redacted]		
Apr-2018	$	88,132
Aug-2018	$	229,498
Dec-2018	$	112,500
Feb-2018	$	72,526
Jan-2018	$	63,728
Jul-2018	$	106,720
Oct-2018	$	78,670
[redacted]		
Apr-2018	$	3,440
Aug-2018	$	3,844
Dec-2018	$	2,356
Feb-2018	$	2,704
Jan-2018	$	2,064
Jul-2018	$	4,144
Jun-2018	$	3,720
Mar-2018	$	1,968
May-2018	$	3,824
Nov-2018	$	3,168
Oct-2018	$	2,360
Sep-2018	$	3,624
[redacted]		
Apr-2018	$	4,036
Aug-2018	$	2,552
Dec-2018	$	4,496
Feb-2018	$	2,912
Jan-2018	$	1,080
Jul-2018	$	3,708
Jun-2018	$	4,792
Mar-2018	$	5,748
May-2018	$	3,908
Nov-2018	$	3,088
Oct-2018	$	2,216
Sep-2018	$	4,724
[redacted]		
Apr-2018	$	2,956
Aug-2018	$	1,980
Dec-2018	$	3,436
Feb-2018	$	2,108
Jan-2018	$	723
Jul-2018	$	2,964
Jun-2018	$	3,200
Mar-2018	$	3,428
May-2018	$	2,852
Nov-2018	$	2,444
Oct-2018	$	1,716
Sep-2018	$	1,468
[redacted]		
Apr-2018	$	504

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Aug-2018	$	360
Feb-2018	$	392
Jan-2018	$	158
Jul-2018	$	484
Jun-2018	$	456
Mar-2018	$	380
May-2018	$	268
Nov-2018	$	292
Oct-2018	$	220
Sep-2018	$	364
[redacted]		
Dec-2018	$	237,915
Feb-2018	$	1,010
Jan-2018	$	65,029
Nov-2018	$	277,355
Oct-2018	$	140,335
[redacted]		
Apr-2018	$	4,573
Aug-2018	$	4,407
Feb-2018	$	6,037
Jan-2018	$	5,123
Jul-2018	$	4,303
Jun-2018	$	7,712
Mar-2018	$	3,123
Nov-2018	$	3,619
Oct-2018	$	3,367
Sep-2018	$	3,609
[redacted]		
Apr-2018	$	2,556
Aug-2018	$	2,652
Dec-2018	$	1,580
Feb-2018	$	1,780
Jan-2018	$	1,280
Jul-2018	$	2,836
Jun-2018	$	2,680
Mar-2018	$	1,444
May-2018	$	2,792
Nov-2018	$	2,184
Oct-2018	$	1,976
Sep-2018	$	2,632
[redacted]		
Sep-2018	$	7,750
[redacted]		
Apr-2018	$	1,740
Aug-2018	$	2,075
Dec-2018	$	1,225
Feb-2018	$	1,445
Jan-2018	$	1,110
Jul-2018	$	2,145
Jun-2018	$	2,030
Mar-2018	$	1,045
May-2018	$	1,945
Nov-2018	$	1,660
Oct-2018	$	1,490

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Sep-2018	$	2,150
[redacted]		
Feb-2018	$	126,791
Jan-2018	$	105,336
Mar-2018	$	37,170
[redacted]		
Apr-2018	$	2,549
Feb-2018	$	2,724
Jul-2018	$	7,508
Oct-2018	$	8,679
[redacted]		
Apr-2018	$	689
Feb-2018	$	8,705
Jul-2018	$	5,786
Oct-2018	$	8,472
[redacted]		
Apr-2018	$	2,670
Aug-2018	$	2,785
Dec-2018	$	1,765
Feb-2018	$	2,140
Jan-2018	$	1,660
Jul-2018	$	3,095
Jun-2018	$	2,975
Mar-2018	$	1,585
May-2018	$	2,975
Nov-2018	$	2,390
Oct-2018	$	2,120
Sep-2018	$	2,905
[redacted]		
Jan-2018	$	20
[redacted]		
Apr-2018	$	4,110
Aug-2018	$	4,885
Dec-2018	$	2,925
Feb-2018	$	3,410
Jan-2018	$	2,660
Jul-2018	$	5,130
Jun-2018	$	4,740
Mar-2018	$	2,540
May-2018	$	4,535
Nov-2018	$	4,120
Oct-2018	$	3,705
Sep-2018	$	5,085
[redacted]		
Apr-2018	$	1,675
Aug-2018	$	3,160
Dec-2018	$	2,630
Feb-2018	$	1,235
Jan-2018	$	2,700
Jun-2018	$	1,770
Mar-2018	$	2,495
May-2018	$	1,485
Nov-2018	$	1,035
Sep-2018	$	1,910

**Information in italices is confidential*

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1191
2018 REPS Compliance Report
Dates and Amounts of Payments for RECs - Calendar Year 2018

Redacted Version
Jennings Exhibit No. 1, Appendix 1
February 26, 2019

Counterparty and Payment Dates		REC Cost
[redacted]		
Apr-2018	$	668
Aug-2018	$	1,436
Dec-2018	$	457
Feb-2018	$	1,602
Jul-2018	$	783
Mar-2018	$	997
May-2018	$	779
Nov-2018	$	556
Oct-2018	$	1,357
[redacted]		
Dec-2018	$	2,644
[redacted]		
Sep-2018	$	8,283
[redacted]		
Apr-2018	$	1,332
Aug-2018	$	1,564
Dec-2018	$	648
Feb-2018	$	596
Jan-2018	$	400
Jul-2018	$	1,688
Jun-2018	$	1,528
Mar-2018	$	740
May-2018	$	1,504
Nov-2018	$	1,236
Oct-2018	$	1,192
Sep-2018	$	1,584
[redacted]		
Apr-2018	$	3,116
Aug-2018	$	3,748
Dec-2018	$	1,728
Feb-2018	$	1,816
Jan-2018	$	1,356
Jul-2018	$	4,012
Jun-2018	$	3,616
Mar-2018	$	1,760
May-2018	$	3,552
Nov-2018	$	2,824
Oct-2018	$	2,760
Sep-2018	$	3,776
[redacted]		
Apr-2018	$	4,060
Aug-2018	$	4,555
Dec-2018	$	2,305
Feb-2018	$	3,035
Jan-2018	$	2,350
Jul-2018	$	4,840
Jun-2018	$	4,400
Mar-2018	$	2,400
May-2018	$	1,360
Nov-2018	$	3,585
Oct-2018	$	3,465
Sep-2018	$	4,580
[redacted]		

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Sep-2018	$	9,824
[redacted]		
Apr-2018	$	2,972
Aug-2018	$	3,216
Dec-2018	$	1,724
Feb-2018	$	2,256
Jan-2018	$	1,732
Jul-2018	$	3,496
Jun-2018	$	3,304
Mar-2018	$	1,760
May-2018	$	3,256
Nov-2018	$	2,004
Oct-2018	$	2,020
Sep-2018	$	3,424
[redacted]		
Apr-2018	$	1,016
Aug-2018	$	316
Dec-2018	$	1,272
Feb-2018	$	644
Jan-2018	$	273
Jul-2018	$	644
Jun-2018	$	1,008
Mar-2018	$	1,040
May-2018	$	1,020
Nov-2018	$	704
Oct-2018	$	296
Sep-2018	$	376
[redacted]		
Apr-2018	$	2,972
Aug-2018	$	3,792
Dec-2018	$	2,168
Feb-2018	$	2,408
Jan-2018	$	1,912
Jul-2018	$	4,044
Jun-2018	$	3,820
Mar-2018	$	1,764
May-2018	$	3,552
Nov-2018	$	3,036
Oct-2018	$	2,696
Sep-2018	$	3,864
[redacted]		
Apr-2018	$	504
Aug-2018	$	480
Dec-2018	$	424
Feb-2018	$	520
Jan-2018	$	480
Jul-2018	$	544
Jun-2018	$	504
Mar-2018	$	488
May-2018	$	556
Nov-2018	$	480
Oct-2018	$	428
Sep-2018	$	544
[redacted]		

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Feb-2018	$	17,000
May-2018	$	17,000
[redacted]		
Apr-2018	$	3,236
Aug-2018	$	4,032
Dec-2018	$	2,300
Feb-2018	$	2,692
Jan-2018	$	2,104
Jul-2018	$	4,148
Jun-2018	$	3,940
Mar-2018	$	1,928
May-2018	$	3,800
Nov-2018	$	2,968
Oct-2018	$	2,716
Sep-2018	$	4,024
[redacted]		
Apr-2018	$	24,450
Aug-2018	$	18,825
Feb-2018	$	25,275
Jan-2018	$	21,945
Jul-2018	$	21,450
Jun-2018	$	23,400
Mar-2018	$	23,250
May-2018	$	26,175
Nov-2018	$	10,950
Oct-2018	$	9,300
Sep-2018	$	19,500
[redacted]		
Apr-2018	$	3,865
Aug-2018	$	4,635
Dec-2018	$	2,625
Feb-2018	$	3,045
Jan-2018	$	2,530
Jul-2018	$	4,785
Jun-2018	$	4,610
Mar-2018	$	2,380
May-2018	$	4,565
Nov-2018	$	3,435
Oct-2018	$	2,450
Sep-2018	$	4,440
[redacted]		
Apr-2018	$	25,734
Aug-2018	$	28,747
Dec-2018	$	18,736
Feb-2018	$	21,553
Jan-2018	$	19,389
Jul-2018	$	30,473
Jun-2018	$	30,049
Mar-2018	$	19,881
May-2018	$	28,445
Nov-2018	$	20,435
Oct-2018	$	23,674
Sep-2018	$	29,247
[redacted]		

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Apr-2018	$	785
Aug-2018	$	963
Dec-2018	$	464
Feb-2018	$	499
Jan-2018	$	348
Jul-2018	$	1,034
Jun-2018	$	963
Mar-2018	$	392
May-2018	$	927
Nov-2018	$	678
Oct-2018	$	606
Sep-2018	$	963
[redacted]		
Apr-2018	$	37,994
Aug-2018	$	42,150
Dec-2018	$	25,971
Feb-2018	$	31,313
Jan-2018	$	27,379
Jul-2018	$	43,631
Jun-2018	$	41,819
Mar-2018	$	27,833
May-2018	$	41,101
Nov-2018	$	27,853
Oct-2018	$	32,954
Sep-2018	$	42,344
[redacted]		
Apr-2018	$	3,968
Aug-2018	$	4,610
Dec-2018	$	2,468
Feb-2018	$	2,788
Jan-2018	$	2,360
Jul-2018	$	5,040
Jun-2018	$	4,718
Mar-2018	$	2,252
May-2018	$	4,611
Nov-2018	$	3,325
Oct-2018	$	3,325
Sep-2018	$	4,719
[redacted]		
Apr-2018	$	3,332
Aug-2018	$	3,580
Dec-2018	$	2,252
Feb-2018	$	2,716
Jan-2018	$	2,072
Jul-2018	$	3,968
Jun-2018	$	3,856
Mar-2018	$	1,992
May-2018	$	3,756
Nov-2018	$	2,892
Oct-2018	$	2,744
Sep-2018	$	3,880
[redacted]		
Jan-2018	$	2,215
[redacted]		

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Apr-2018	$	3,400
Aug-2018	$	4,128
Dec-2018	$	2,184
Feb-2018	$	2,792
Jan-2018	$	2,076
Jul-2018	$	4,292
Jun-2018	$	3,844
Mar-2018	$	2,056
May-2018	$	3,884
Nov-2018	$	3,200
Oct-2018	$	2,180
Sep-2018	$	4,208
[redacted]		
Apr-2018	$	1,995
Aug-2018	$	2,168
Dec-2018	$	1,325
Feb-2018	$	1,488
Jan-2018	$	1,123
Jul-2018	$	2,308
Jun-2018	$	2,143
Mar-2018	$	1,153
May-2018	$	2,163
Nov-2018	$	1,788
Oct-2018	$	1,655
Sep-2018	$	2,143
[redacted]		
Apr-2018	$	344
Aug-2018	$	432
Dec-2018	$	264
Feb-2018	$	272
Jan-2018	$	212
Jul-2018	$	404
Jun-2018	$	404
Mar-2018	$	196
May-2018	$	480
Nov-2018	$	380
Oct-2018	$	276
Sep-2018	$	444
[redacted]		
Apr-2018	$	1,798
Aug-2018	$	1,985
Dec-2018	$	1,231
Feb-2018	$	1,436
Jan-2018	$	1,069
Jul-2018	$	2,050
Jun-2018	$	1,953
Mar-2018	$	1,044
May-2018	$	1,976
Nov-2018	$	1,658
Oct-2018	$	1,573
Sep-2018	$	2,039
[redacted]		
Apr-2018	$	174,478
Aug-2018	$	94,288

*Information in italices is confidential

Counterparty and Payment Dates		REC Cost
Dec-2018	$	286,026
Feb-2018	$	181,906
Jan-2018	$	197,751
Jul-2018	$	229,930
Mar-2018	$	188,664
May-2018	$	105,836
Nov-2018	$	276,958
Oct-2018	$	216,730
Sep-2018	$	218,870
[redacted]		
Apr-2018	$	286,126
Aug-2018	$	286,636
Dec-2018	$	369,816
Feb-2018	$	195,268
Jan-2018	$	251,387
Jul-2018	$	495,902
Mar-2018	$	287,688
May-2018	$	212,508
Nov-2018	$	406,402
Oct-2018	$	318,406
Sep-2018	$	419,394
[redacted]		
Apr-2018	$	37,426
Aug-2018	$	45,382
Dec-2018	$	70,812
Feb-2018	$	46,905
Jan-2018	$	26,835
Jul-2018	$	69,812
Mar-2018	$	43,172
May-2018	$	35,406
Nov-2018	$	63,084
Oct-2018	$	48,620
Sep-2018	$	61,388
[redacted]		
Mar-2018	$	1,678
[redacted]		
Apr-2018	$	3,810
Aug-2018	$	4,650
Dec-2018	$	2,350
Feb-2018	$	2,660
Jan-2018	$	2,165
Jul-2018	$	4,780
Jun-2018	$	4,610
Mar-2018	$	2,210
May-2018	$	4,400
Nov-2018	$	3,380
Oct-2018	$	3,365
Sep-2018	$	4,755
[redacted]		
Apr-2018	$	1,665
Aug-2018	$	1,928
Dec-2018	$	1,206
Feb-2018	$	1,400
Jan-2018	$	1,105

**Information in italices is confidential*

Counterparty and Payment Dates		REC Cost
Jul-2018	$	1,877
Jun-2018	$	1,843
Mar-2018	$	1,008
May-2018	$	1,892
Nov-2018	$	1,409
Oct-2018	$	1,301
Sep-2018	$	1,886
[redacted]		
Apr-2018	$	1,300
Aug-2018	$	1,640
Dec-2018	$	840
Feb-2018	$	880
Jan-2018	$	700
Jul-2018	$	1,668
Jun-2018	$	1,604
Mar-2018	$	800
May-2018	$	1,520
Nov-2018	$	1,088
Oct-2018	$	1,112
Sep-2018	$	1,648
[redacted]		
Apr-2018	$	14,041
Aug-2018	$	12,481
Dec-2018	$	15,531
Feb-2018	$	14,674
Jan-2018	$	12,803
Jul-2018	$	12,680
Jun-2018	$	12,739
Mar-2018	$	12,563
May-2018	$	12,856
Nov-2018	$	13,478
Oct-2018	$	12,187
Sep-2018	$	13,513
[redacted]		
Apr-2018	$	2,280
Aug-2018	$	2,608
Dec-2018	$	1,524
Feb-2018	$	1,848
Jan-2018	$	1,368
Jul-2018	$	2,768
Jun-2018	$	2,584
Mar-2018	$	1,272
May-2018	$	2,656
Nov-2018	$	2,128
Oct-2018	$	1,804
Sep-2018	$	2,652
[redacted]		
Apr-2018	$	1,272
Aug-2018	$	1,456
Dec-2018	$	844
Feb-2018	$	972
Jan-2018	$	752
Jul-2018	$	1,588
Jun-2018	$	1,436

Counterparty and Payment Dates		REC Cost
Mar-2018	$	756
May-2018	$	1,444
Nov-2018	$	1,180
Oct-2018	$	1,144
Sep-2018	$	1,512

[END CONFIDENTIAL]

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REDACTED VERSION

Jennings Exhibit No. 2
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February 26, 2019

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191

Compliance Costs

			EMF Period January 1, 2018 - December 31, 2018				Billing Period September 1, 2019 - August 31, 2020			
Line No.	Renewable Resource	RECs only	Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs	Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs

[redacted]

REDACTED VERSION

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191

Compliance Costs

Line No.	Renewable Resource	RECs only	EMF Period January 1, 2018 - December 31, 2018 Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs	Billing Period September 1, 2019 - August 31, 2020 Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs
[redacted]										

REDACTED VERSION

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191

Compliance Costs

Line No.	Renewable Resource	RECs only	EMF Period January 1, 2018 - December 31, 2018: Total Units (A)(B)	Total Cost per Unit	Total Cost	RECs	Billing Period September 1, 2019 - August 31, 2020: Total Units (A)(B)	Total Cost per Unit	Total Cost	RECs
[redacted]										

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191

Compliance Costs

Line No.	Renewable Resource	RECs only	EMF Period January 1, 2018 - December 31, 2018 Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs	Billing Period September 1, 2019 - August 31, 2020 Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs
[redacted]										

REDACTED VERSION

Compliance Costs

Line No.	Renewable Resource	RECs only	EMF Period January 1, 2018 - December 31, 2018 Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs	Billing Period September 1, 2019 - August 31, 2020 Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs
[redacted]										

Compliance Costs

Line No.	Renewable Resource	RECs only	EMF Period January 1, 2018 - December 31, 2018 Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs	Billing Period September 1, 2019 - August 31, 2020 Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs
[redacted]										

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191

Compliance Costs

Line No.	Renewable Resource	RECs only	EMF Period January 1, 2018 - December 31, 2018 Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs	Billing Period September 1, 2019 - August 31, 2020 Total Units (A) (B)	Total Cost per Unit	Total Cost	RECs
[redacted]										
1	Other Incremental (see Jennings Exhibit No. 3 for Incremental Cost worksheet)				$ 1,030,461				$ 1,567,500	
2	Billing Period estimated receipts related to contract performance				$ -	Note 1			$ (1,000,000)	Note 1
3	Solar Rebate Program (see Jennings Exhibit No. 3 for cost detail)				$ 135,912				$ 1,137,395	
4	Research (see Jennings Exhibit No. 3 for Research cost detail)				$ 938,393				$ 895,000	
5	**Total Other Incremental and Research Cost**				$ 2,104,766				$ 2,599,895	
[redacted]										
1	EMF Period actual credits for receipts related to contracts - to Williams Exhibit No.4 - footnote (3)				$ (1,011,160)	Note 1				

Note 1: EMF Period contract receipts are not included in the under/overcollection calculation on Williams Exhibit No. 2, instead they are credited directly to customer class on Williams Exhibit No. 4. Estimated contract receipts are included in Billing Period total other incremental cost as a reduction in REPS charges proposed for the Billing Period.

Footnotes: [redacted]

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DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191

Jennings Exhibit No. 3
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February 26, 2019

REDACTED VERSION*

Line No.	Incremental Cost Worksheet:		EMF Period Jan 2018 - Dec 2018		Projected Billing Period Sep 2019 - Aug 2020
	Labor by activity:				
1	[redacted]				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23	Total Other Incremental Cost	$	1,030,461	$	1,567,500
	Solar Rebate Program Cost Detail (recovery in REPS pursuant to G.S. 62-155(f)): (1)				
24	Annual Amortization of Incentives Provided to Customers, plus return on unamortized balance		128,528	$	1,055,610
25	Annual Amortization of Program Administrative Labor Costs, plus return on unamortized balance		[redacted]		
26	Annual Amortization of Program Administrative Contract Labor & Other Administrative Costs, plus return on unamortized balance				
27	Total Solar Rebate Program Cost	$	135,912	$	1,137,395

(1) All annual Solar Rebate Program costs reflect amortization of incurred costs over 20 years, including a return on the unamortized balance.

REDACTED VERSION*

Line No.	Incremental Cost Worksheet:		EMF Period Jan 2018 - Dec 2018		Projected Billing Period Sep 2019 - Aug 2020
	Research Cost Detail:				
28	CAPER - Short Course Development		[redacted]		
29	CAPER - Smart Battery Gauge				
30	Clemson University - Small DG Interface Testing				
31	Closed Loop Biomass				
32	Coalition for Renewable Natural Gas Membership				
33	DER Risks to Transformers and Transmission				
34	Eos Energy Storage Technology Development - McAlpine				
35	EPRI Membership				
36	EPRI - Inverter Onboard Islanding Detection Case Study Project				
37	ETO - Mitigation of Transformer High Inrush Current				
38	FREEDM Center - NCSU				
39	IEEE 1547 Conformity Assessment Test				
40	Loyd Ray Farms - Duke University				
41	Marshall Solar Site Storage Integration and Controller Design				
42	Mini-DVAR				
43	NCSU - ETO - Grid-forming Battery Energy Storage System Characterization & Testing				
44	NCSU - Interactions of PV Installations with Distribution Systems				
45	PNNL - Dynamic Var Compensator Pilot				
46	Research Triangle Institute - Biogas Utilization in NC				
47	Rocky Mountain Institute - eLab				
48	Swine Extrusion/Poultry Mortality - NC State Natural Resources Foundation				
49	UNCC - Evaluation of Fault Scenarios and Mitigation Techniques				
50	UNCC - Hardware Cyber Security for DER Inverters				
51	**Total Research Cost**	$	938,393	$	895,000
52	**Total Other Incremental Cost**	$	1,030,461	$	1,567,500
53	Projected credits for receipts related to contract amendments/liquidated damages, etc		[redacted]	$	(1,000,000)
54	**Total Other Incremental Cost and other credits**	$	1,030,461	$	567,500
55	**Total Solar Rebate Program Cost**		135,912	$	1,137,395
56	**Total Research Cost**		938,393	$	895,000
57	**Grand Total - Other Incremental, Solar Rebate Program, and Research Cost, other credits**	$	2,104,766	$	2,599,895
58	EMF Period actual credits for receipts related to contracts - see Note 1	$	(1,011,160)		
59	**Net Other Incremental, Solar Rebate Program and Research Cost**	$	1,093,606	$	2,599,895

Note 1: EMF Period contract receipts are not included in the under/overcollection calculation on Williams Exhibit No. 2, instead they are credited directly to customer class on Williams Exhibit No. 4. Estimated contract receipts are included in Billing Period total other incremental cost as a reduction in REPS charges proposed for the Billing Period

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REDACTED VERSION

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191
REC sales for EMF Period January 1, 2018 - December 31, 2018

Jennings Exhibit No. 4
Page 1 of 1
February 26, 2019

Note:

Pursuant to the Commission's May 13, 2014 *Order Regarding Accounting Treatment For REC Sales* issued in Docket No. E-100, Sub 113, the Company provides the following transaction details for all RECs sold by the Company during the calendar year 2018 REPS rider true-up (EMF) period. All REC sales transactions for the test period involved selling RECs to other electric power suppliers in the State for the purpose of meeting the aggregate poultry compliance requirement for the 2017 compliance year.

Line No.	Month RECs sold	Fuel Type (NC-RETS)	REC Vintage	Quantity	Original purchase price / REC	Sales price / REC	Sales proceeds (a)	Incremental transaction costs (1) (b)	Interest (2) (c)	Net proceeds from REC sales (a) - (b) - (c)	Cost of replacement RECs
[redacted]											

Footnotes:

(1) No incremental administrative costs, brokerage fees, or other transaction costs were identified with respect to these REC sales.

[redacted]

(3) All REC sales transactions were made in support of the meeting the 2017 statewide aggregate poultry compliance requirement, and no poultry REC purchases by the Company were specifically obtained or identified as replacements for the RECs sold.

(4) Net REC sales proceeds are included as a credit in Other Incremental Cost for the EMF period as detailed in the worksheet reflected on Jennings Exhibit No. 3.

**Information in italics is confidential*

CAPER Summer Course
Fundamentals of Power Engineering and Integration of Distributed Energy Resources

Instructors:

Dr. Ramtin Hadidi	rhadidi@clemson.edu	843-730-5106
Dr. Johan Enslin	jenslin@clemson.edu	843-730-5117
Dr. Randy Collins	collins@clemson.edu	864-656-9289
Dr. Ning Lu	nlu2@ncsu.edu	919-513-7529
Dr. David Lubkeman	dllubkem@ncsu.edu	919-513-2024
Dr. Mesut Baran	baran@nscu.edu	919-515-5081
Dr. Badrul Chowdhury	b.chowdhury@uncc.edu	704-687-1960
Dr. Valentina Cecchi	vcecchi@uncc.edu	704-687-8730
Kim Craven	kim.craven@duke-energy.com	704-995-4061
Steven Whisenant	steven.whisenant@duke-energy.com	704-877-1265

References: A copy of the textbook will be provided to each registered student.

- Power System Analysis & Design, 6th Ed. by Glover, Overbye & Sarma, CL Engineering, 2016

Additional references:

- Class notes
- Power point slides

Course Objectives: This five-week course will provide a comprehensive overview of the fundamentals of power engineering. Topics include Three-phase fundamentals, transformers, power Flows, Power System Planning, Analysis, Protection, Dynamics, Stability, Control, Transients, and Distributed Energy Resources and Integration into the Grid. The course is designed to act as a refresher for the basics and as a brief introduction for more advanced topics.

At the completion of the course, student should be able to:

- Perform three-phase analysis
- Understand the per-unit system
- Analyze transmission line electrical performance
- Understand and perform power flow analysis
- Perform balanced and unsymmetrical fault calculations
- Understand symmetrical components and their role in unsymmetrical fault analysis
- Analyze symmetrical and unsymmetrical short circuit scenarios
- Understand different form of stability studies

Software: PowerWorld, PSSE, CYME, MS Office, and MATLAB will be required at minimum.

CAPER

Summer Course Syllabus | Summer 2019

Lecture: Monday, May 13th – Friday, May 17h, 2019
Monday, June 10th – Friday, June 14th, 2019
8:00 am – 4:30 pm, daily

Class credit: PDH Certificate

Office hours: By appointment.

Prerequisites: This course is designed for industry professionals who have completed at least a Bachelors of Science degree in Electrical Engineering or have adequate work experience.

Admin Information: Crista Hartenstein (charten@clemson.edu)
Office location: Zucker Graduate Education Center
Office hours: Monday – Friday, 9 am – 4 pm

Course Outline:

Before Course Begin: Self-review *Chapter 1: Introduction* and *Chapter 2: Fundamentals*

Week 1:

Day 1	9:00 am – 12:00 pm	Review *Chapter 1: Introduction*
		Review *Chapter 2: Fundamentals*
	12:00 pm – 1:00 pm	Lunch
	1:00 pm – 4:00 pm	*Chapter 3: Transformers and the Per-Unit System*
Day 2	9:00 am – 12:00 pm	*Chapter 4: Rotating Synchronous Machinery – Generators*
	12:00 pm – 1:00 pm	Lunch
	1:00 pm – 4:00 pm	*Chapter 5: Transmission Lines*
Day 3	9:00 am – 12:00 pm	*Chapter 6: Electric Power Substations*
	12:00 pm – 1:00 pm	Lunch
	1:00 pm – 4:00 pm	*Chapter 7: Power System Analysis – Distribution Systems*
Day 4	9:00 am – 12:00 pm	*Chapter 8: Electric Power Utilization*
	12:00 pm – 1:00 pm	Lunch
	1:00 pm – 4:00 pm	*Chapter 9: Power System Analysis – Power Flow*
Day 5	9:00 am – 11:30 am	Self-study assignment:
		Chapter 10: Power Systems Planning and
		Chapter 11: Operation of the Power Systems
	11:30 am – 12:30 pm	Lunch
	12:30 pm – 2:30 pm	Technical site visit and tour

Weeks 2 - 4: Self-study assignment: *Chapters 10: Power System Planning* and *Chapter 11: Operation of the Power Systems*

Week 5:

Day 1	9:00 am – 12:00 pm	Review of Week 1, Midterm test & feedback
	12:00 pm – 1:00 pm	Lunch
	1:00 pm – 4:00 pm	*Chapter 12: Power Systems Analysis - Faults*

Day 2	9:00 am – 12:00 pm	*Chapter 12: Power Systems Analysis – Faults*, continued
	12:00 pm – 1:00 pm	Lunch
	1:00 pm – 4:00 pm	*Chapter 13: Power System Protection*
Day 3	9:00 am – 12:00 pm	*Chapter 14: Power System Dynamics, Stability, and Control*
	12:00 pm – 1:00 pm	Lunch
	1:00 pm – 4:00 pm	*Chapter 15: Power System Transients*
Day 4	9:00 am – 12:00 pm	*Chapter 16: Distributed Energy Resources and Integration into the Grid*
	12:00 pm – 1:00 pm	Lunch
	1:00 pm – 4:00 pm	*Chapter 16: Renewables*, continued
Day 5	9:00 am – 12:00 pm	*Chapter 17: Power Quality*
	12:00 pm – 1:00 pm	Lunch
	1:00 pm – 2:00 pm	Final test & feedback

Pricing:

- CAPER Members: $2,495
- Non-CAPER Members: $2,995
- Early Bird discount: Register by April 19th, 2019 and the membership rate is $2,245

Important Dates:

- Registration open: February 1st, 2019
- Early Bird deadline: April 19th, 2019
- Course begin: May 13th, 2019

To register, please visit http://caper-usa.com/university-programs/professional-development/caper-summer-course/

Classroom Policies: Attendance is voluntary but strongly encouraged. No make up for missed classes, quizzes, or assignments will be given. Students are responsible for all material covered and all assignments given in every lecture. Some lectures may cover material not found in the textbook. It is the responsibility of each student to make up any deficiencies that result from missed classes. Students are expected to wait 15 minutes before leaving if the instructor is late. Cell phones must be turned off or silenced before coming into class.

Changes to Syllabus: The instructors reserve the right to make changes to this syllabus during the semester. Students will be given adequate notice in class of any changes.

Agreement: If you disagree with any of the policies or procedures spelled out above or cannot accept the demands of the course (i.e., the amount of time and work required), you need to drop the course as soon as possible. By staying in the course, you agree to comply with all the policies and procedures described in this syllabus

I/A

JENNINGS CONFIDENTIAL EXHIBIT NO. 6

DOCKET NO. E-7, SUB 1191

CONFIDENTIAL – FILED UNDER SEAL

I/A

JENNINGS CONFIDENTIAL EXHIBIT NO. 7

DOCKET NO. E-7, SUB 1191

CONFIDENTIAL – FILED UNDER SEAL

Jennings Exhibit No. 8
Docket No. E-7, Sub 1191

I/A

2018 Inventory Report

SC8 Biomass Project

AMERICAN FOREST
MANAGEMENT

December 2018

Table of Contents

Inventory Report
SC8 Biomass Project

December, 2018

Executive Summary

This report comprises the 2018 inventory report for biomass crops on the SC8 property in Chester County, SC. It contains several sections:

- Project history
- Inventory data
- Analysis and conclusions
- Recommendations for future management

After the initial project planning was complete in 2009 and 2010, three general biomass research areas were established:

1. Loblolly Nelder Plot: Investigate effects of stand density and genetics on loblolly pine growth.
2. High Density Loblolly Pine Plantations: Investigate effects of stand density on loblolly pine growth for two selected spacings (1082 and 1452 trees per acre)
3. Hardwood Plantations on Upland and Bottomland Sites: Investigate growth of 5 hardwood species (cottonwood, hybrid poplar, aspen, sweetgum, and black willow) on two sites types (upland and bottomland).

Results from the Nelder plot indicate that, for short-rotation biomass crops, there is little difference in the performance of the three broad loblolly pine genotypes tested: (1) Open-pollinated 2nd generation orchard seedlings; (2) Mass-controlled pollinated seed from 2nd generation orchards; and (3) Clonal material from good performing clones. The most economical 2nd-generation seedlings should be used to minimize establishment costs. There is some evidence from the study that containerized material is superior in performance than bareroot seedlings. If the marginal cost increase of containerized versus bareroot material is not excessive it would be a recommended choice. While there is still some uncertainty in an ideal loblolly pine biomass planting density, somewhere between 800 and 1,000 trees per acre is suggested as the best combination of overall yield and economical establishment cost for biomass production.

Results from the high-density loblolly plantings suggest that 1082 trees per acre is a better choice than 1452 trees per acre. The 1082 density has the additional advantage of outperforming the 1452 density in the event of conversion to a traditional timber management regime.

For the 2011 upland site planted to poplar and aspen, both species have similar yields at age 7. Both species have most likely passed the age of their maximum mean annual increment, suggesting that they should be harvested as soon as suitable market and operating conditions exist. Following harvest the second rotation yields from coppice and root sprouts can be evaluated.

The bottomland sites were planted in 2012 to sweetgum, black willow, cottonwood, and hybrid poplar. At the time of the 2018 measurement (age 6) the hybrid poplar block had the highest yields followed by the blocks planted to cottonwood, black willow, and sweetgum. The data for the cottonwood and hybrid poplar plots suggest ages 8 to 10 to be ones that would be optimal for the first rotation biomass harvest which would then be followed by a coppice rotation. The growth of biomass in the black willow from the 2015 to the 2018 exceeded the growth in the other species' blocks. As expected based on its general growth characteristics, sweetgum has lower short-rotation biomass yields than the other three species. However, an advantage of sweetgum (and to some extent cottonwood) is that it provides the management flexibility to produce both biomass and higher-valued product yields for the landowner.

Data analysis was restricted to biometrics only; no specific economic analyses were performed. Final conclusions and operational recommendations should consider seedling costs, establishment and maintenance cost differences over multiple rotations, and operational factors, not the least of which is harvesting cost.

While the project has reached its end, consideration should be given to maintenance of research sites for future evaluation. Maintenance generally consists of periodic inspections to verify site health and integrity. Existing projections and conclusions can be improved through additional formal inventories and analysis in 2021.

Project History

The SC8 property was acquired in 2007 as a potential power generation site. In 2009, with no concrete plans for generation development, attention was turned to establishing a site for biomass crop evaluations. Several goals were established: Develop a knowledge base for biomass crop establishment and management; grow biomass crops and investigate their yields; and provide a demonstration site for potential biomass producers to evaluate growth and yield in an operational setting.

Starting in 2011, a number of woody biomass crops were established:

- Loblolly pine
- Cottonwood
- Aspen
- Hybrid poplar

Additional hardwood plantings were established in 2012 on bottomland sites:

- Cottonwood
- Aspen
- Hybrid poplar
- Sweetgum
- Black willow

With the exception of black willow, a number of different genotypes for each species were planted.

Since establishment, crops have been maintained through a variety of methods (fertilization, insect control, weed control), regularly inspected, and were formally inventoried in 2015 and 2018.

Inventory Data

This section describes the results of the 2018 inventory project. It is divided into sections by species group and subsections by categories within each group. Inventory job control specifications, including tract maps, cruise maps, and specific data collection procedures, can be found in Appendix 1.

Loblolly Nelder Plot

A Nelder plot, also called a Nelder Wheel or Nelder Fan, is a systematic planting design in which plants or trees are planted at the intersection of circular arcs and linear spokes. In general, Nelder plots allow many different planting densities to be examined in a single plot. This is frequently more efficient and requires less area than planting a different plot for each planting density. Nelder plots can be constructed that allow the effect of different planting geometries to be examined in a single plot.

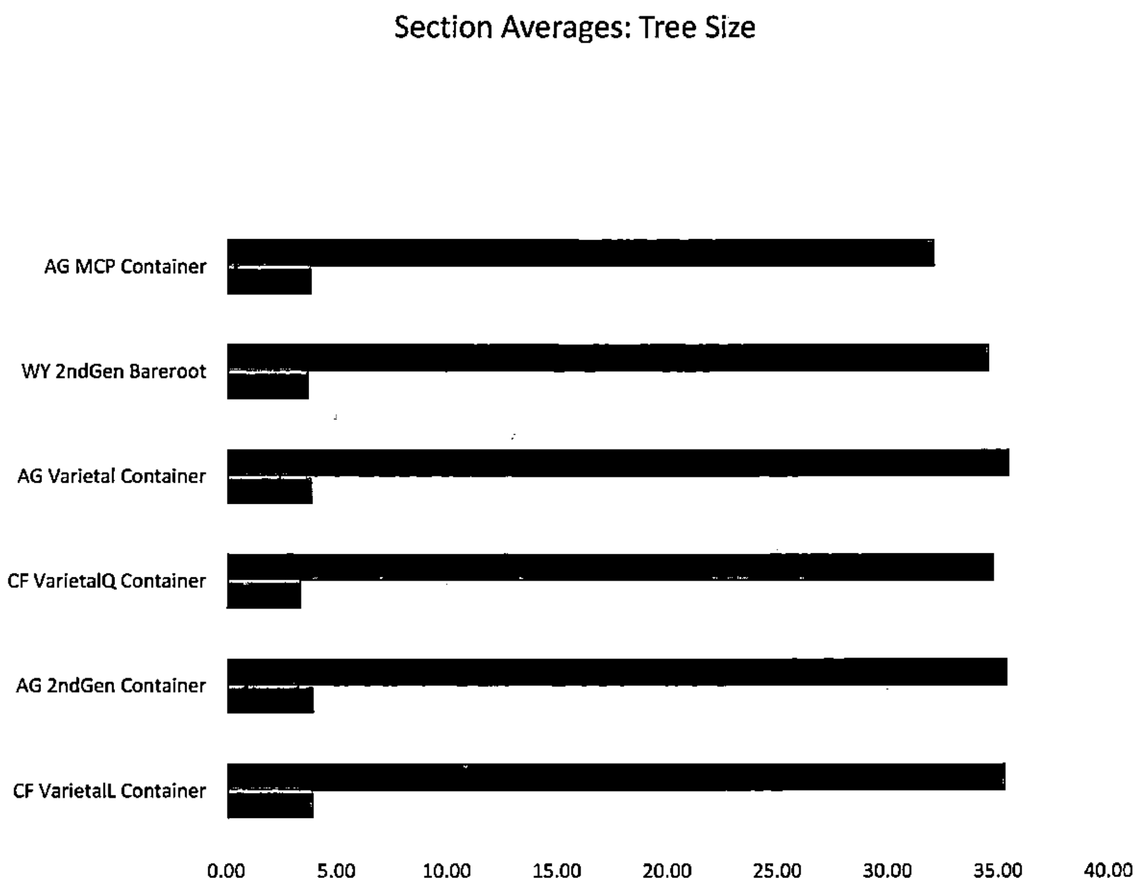
The layout and genotype composition for the SC8 Nelder plot can be found in Appendix 1, Loblolly Nelder Schematic Map. Planting density ranges from 1,349 trees per acre (TPA) at the center to 39 TPA at the perimeter. The Nelder plot was established in February 2011. Its location can be found in Appendix 1, Overview Map.

Table 1. Nelder planting stock and identification

Nelder Section Code	Producer	Planting Stock	Variety	Producer and Variety	Classification	Graph Label
A	CELLFOR	Containerized	L-3791 128L	CELLFOR L-3791 128L	Varietal	CF VarietalL Container
B	ArborGen	Containerized	AG-88 LB-A02-09	ArborGen AG-88 LB-A02-09	2nd Generation Orchard Pollination	AG 2ndGen Container
C	CELLFOR	Containerized	Q-7766 128L	CELLFOR Q-7766 128L	Varietal	CF VarietalQ Container
D	ArborGen	Containerized	AVG-102	ArborGen AVG-102	Varietal	AG Varietal Container
E	WeyCo	Bareroot	007056.LD	WeyCo 007056.LD	2nd Generation Orchard Pollination	WY 2ndGen Bareroot
F	ArborGen	Containerized	AGM-37 LB SBI-09E	ArborGen AGM-37 LB SBI-09E	Mass Controlled Polination	AG MCP Container

Figures 1 through 4 show the average values for each of the Nelder sections.

<u>Figure 1. Height and diameter by genotype</u>

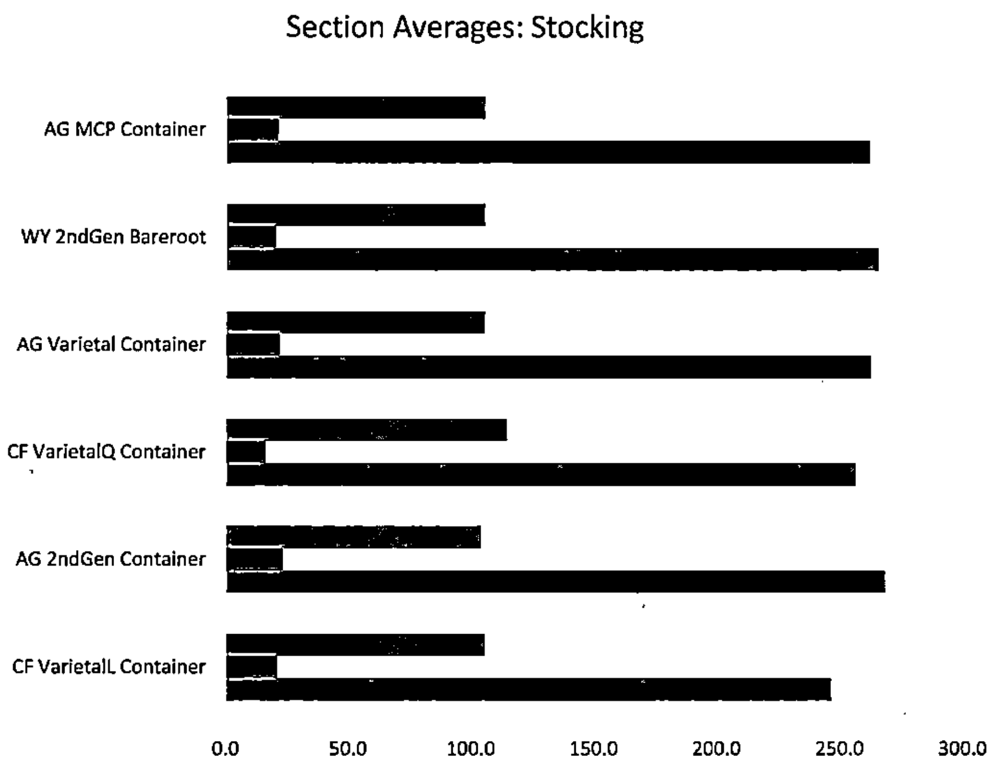


	CF VarietalL Container	AG 2ndGen Container	CF VarietalQ Container	AG Varietal Container	WY 2ndGen Bareroot	AG MCP Container
■ Dominant Ht (ft)	35.32	35.38	34.79	35.50	34.57	32.12
■ Average DBH - Dg (in)	3.94	3.97	3.40	3.91	3.73	3.87

■ Dominant Ht (ft) ■ Average DBH - Dg (in)

Figure 2. Stocking by genotype

Displays growing space per tree, basal area per hectare, and live trees per acre for each genotype.

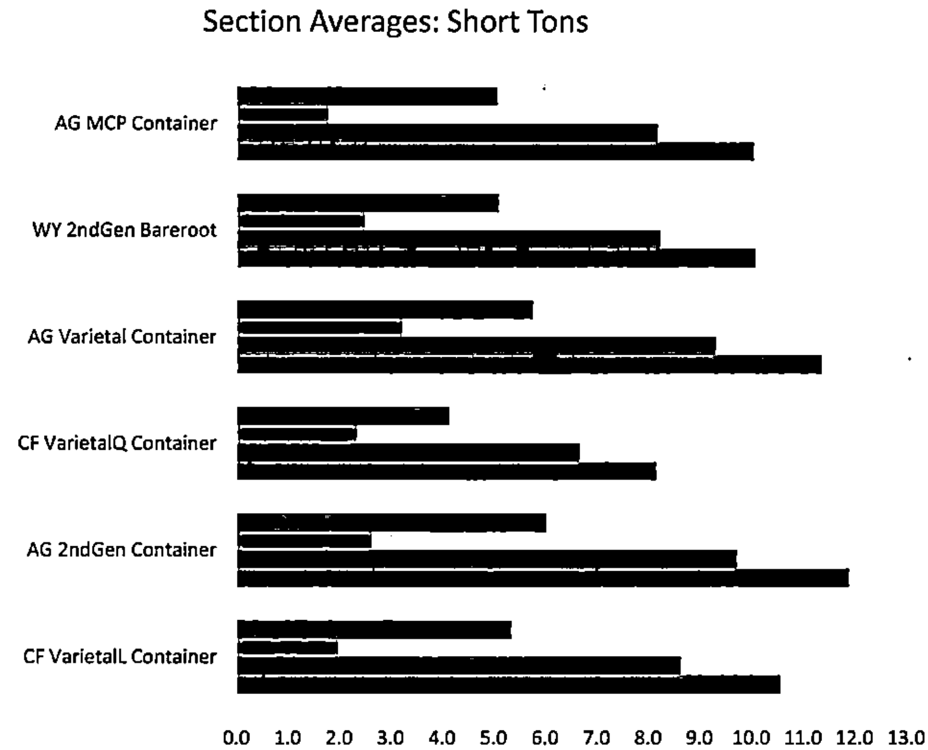


	CF VarietalL Container	AG 2ndGen Container	CF VarietalQ Container	AG Varietal Container	WY 2ndGen Bareroot	AG MCP Container
■ Space per Living Tree	105.7	104.1	114.7	105.7	105.7	105.7
■ Basal Area per Hectare (ft^2)	20.9	23.1	16.2	21.9	20.2	21.4
■ Live Trees / acre	246.6	268.4	256.5	262.8	265.8	262.3

■ Space per Living Tree ■ Basal Area per Hectare (ft^2) ■ Live Trees / acre

Figure 3. Tree weight by genotype

Displays tons per acre for total dry weight outside bark (TDWOB), merchantable green weight outside bark (MGWOB), main stem total green weight outside bark (TGWOB), and entire tree total green weight outside bark (TGWOBAll).



	CF VarietalL Container	AG 2ndGen Container	CF VarietalQ Container	AG Varietal Container	WY 2ndGen Bareroot	AG MCP Container
■ TDWOB (short tons/acre)	5.3	6.0	4.1	5.8	5.1	5.1
■ MGWOB4in dbh>=5" (short tons/acre)	2.0	2.6	2.3	3.2	2.5	1.8
■ TGWOB (short tons/acre)	8.6	9.7	6.7	9.3	8.2	8.2
■ TGWOBAll (short tons/acre)	10.6	11.9	8.2	11.4	10.1	10.0

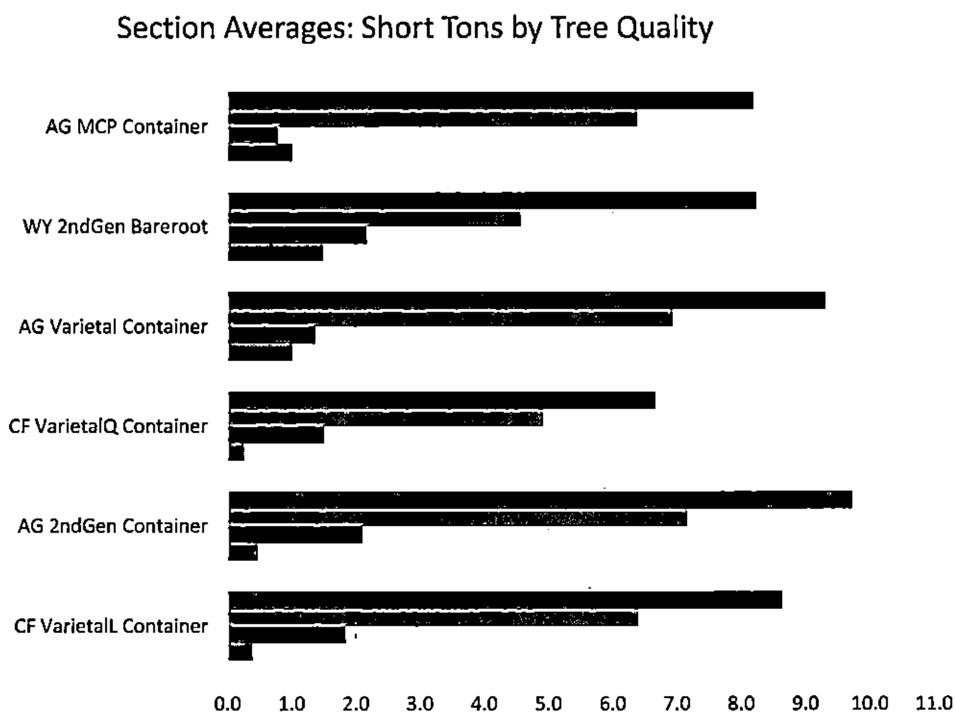
Short Tons / Acre

■ TDWOB (short tons/acre) ■ MGWOB4in dbh>=5" (short tons/acre)

■ TGWOB (short tons/acre) ■ TGWOBAll (short tons/acre)

Figure 4. Tree weight by tree quality

1: Always pulpwood 2: Potential sawtimber 3: Definite sawtimber



	CF VarietalL Container	AG 2ndGen Container	CF VarietalQ Container	AG Varietal Container	WY 2ndGen Bareroot	AG MCP Container
■ TGWOB (short tons/acre)	8.6	9.7	6.7	9.3	8.2	8.2
■ TGWOB (short tons/acre) Quality = 3	6.4	7.2	4.9	6.9	4.6	6.4
■ TGWOB (short tons/acre) Quality = 2	1.8	2.1	1.5	1.4	2.2	0.8
■ TGWOB (short tons/acre) Quality = 1	0.4	0.5	0.3	1.0	1.5	1.0

Short Tons / Acre

■ TGWOB (short tons/acre) ■ TGWOB (short tons/acre) Quality = 3

■ TGWOB (short tons/acre) Quality = 2 ■ TGWOB (short tons/acre) Quality = 1

Figures 5 through 9 illustrate various combined average values for all sections for the different trees per acre classes represented by each ring of the Nelder plot.

Figure 5. Average weight by trees per acre

These weight categories are: main stem green weight outside bark (TGWOB), entire tree green weight outside bark (TGWOBAll), merchantable stem green weight outside bark (MGWOB), and dry weight outside bark (TDWOB).

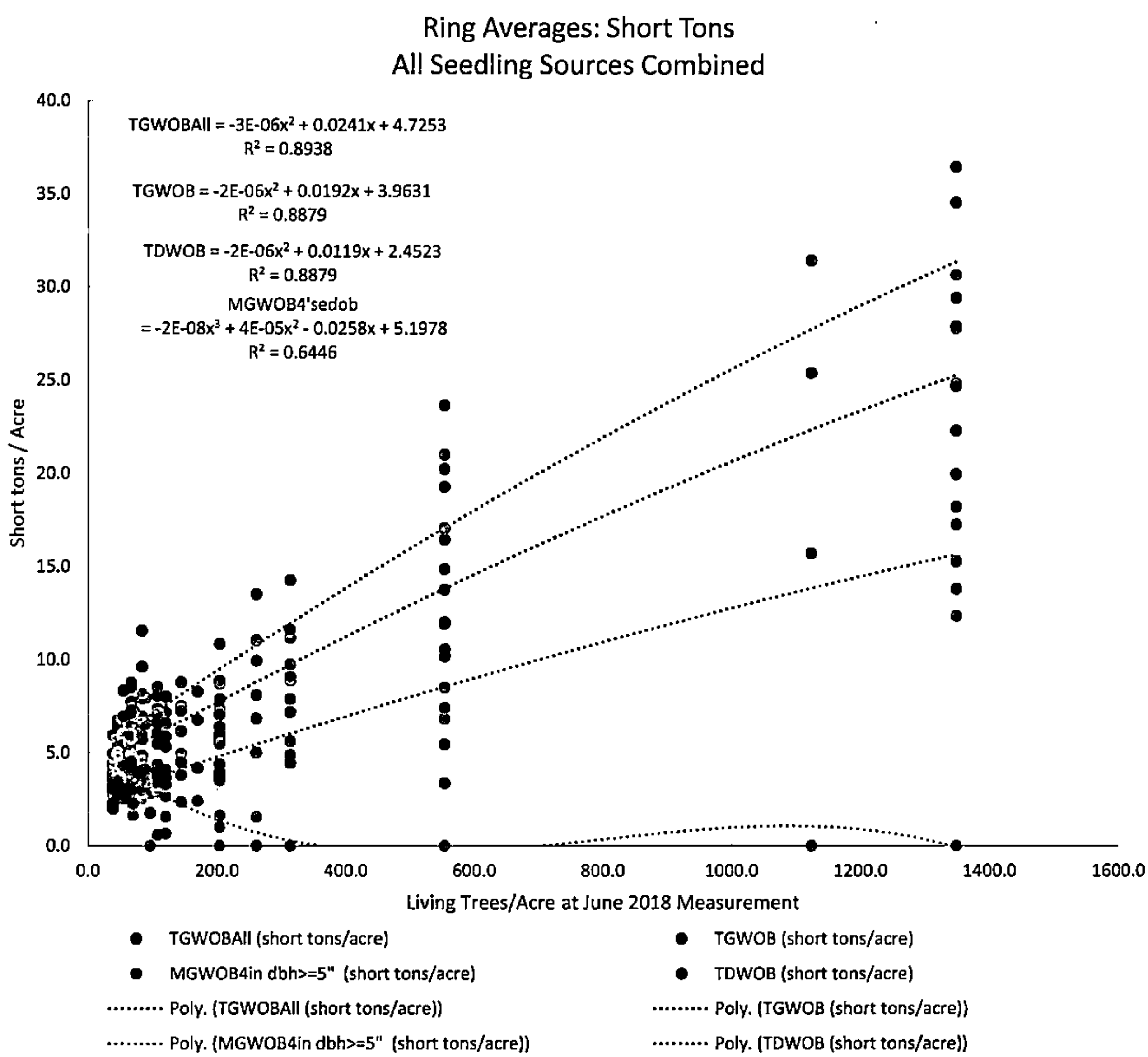


Figure 6. Average weight by seedling type and trees per acre

Displays weight for varietal container-grown, orchard-mix container-grown, orchard-mix bareroot, and mass-control pollinated container-grown.

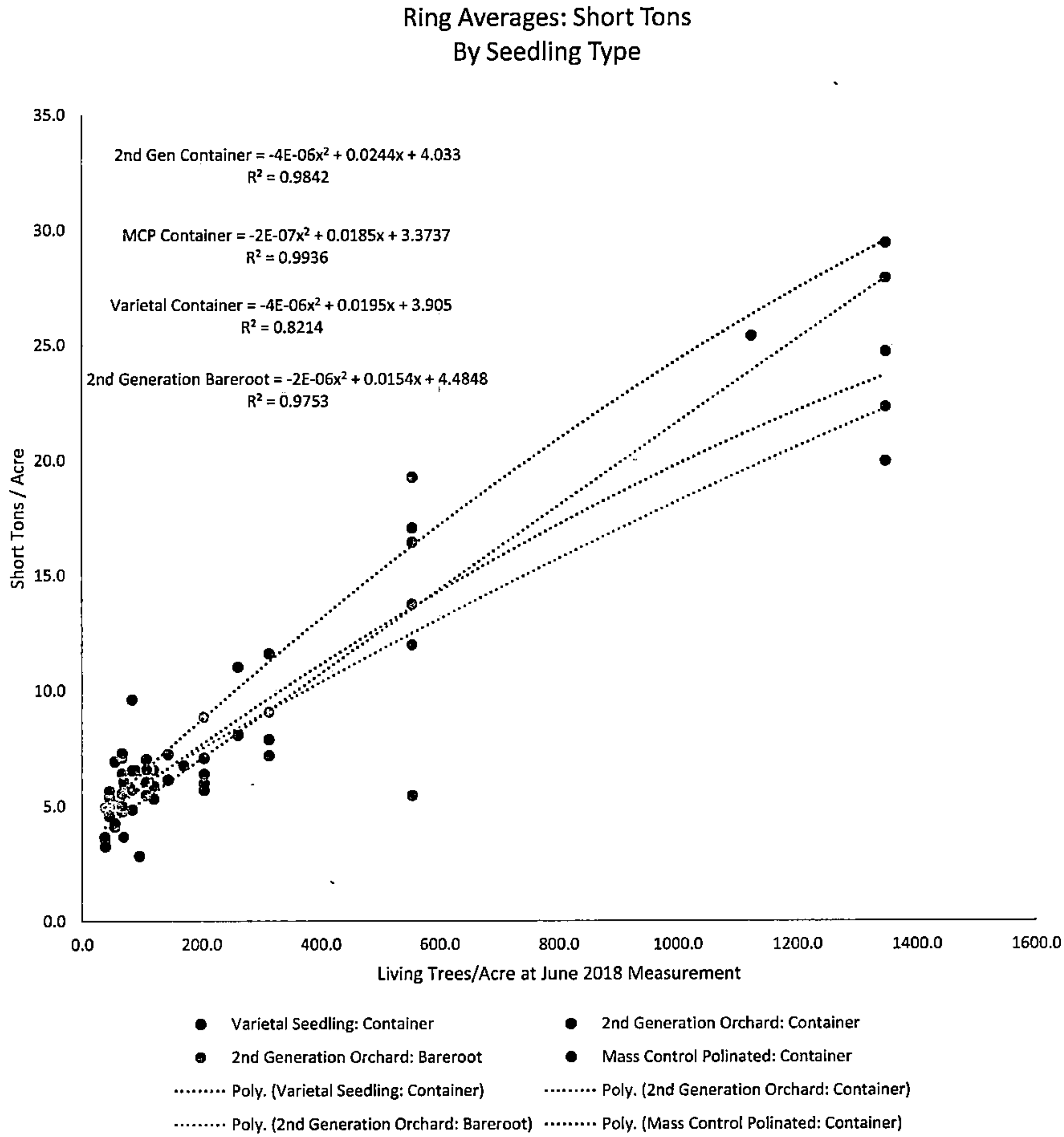


Figure 7. Overall basal area per acre and quality 3 basal area by planting density

Displays basal area for all trees regardless of quality, and only those trees meeting quality grade 3 (definite sawtimber), as growing space per tree changes.

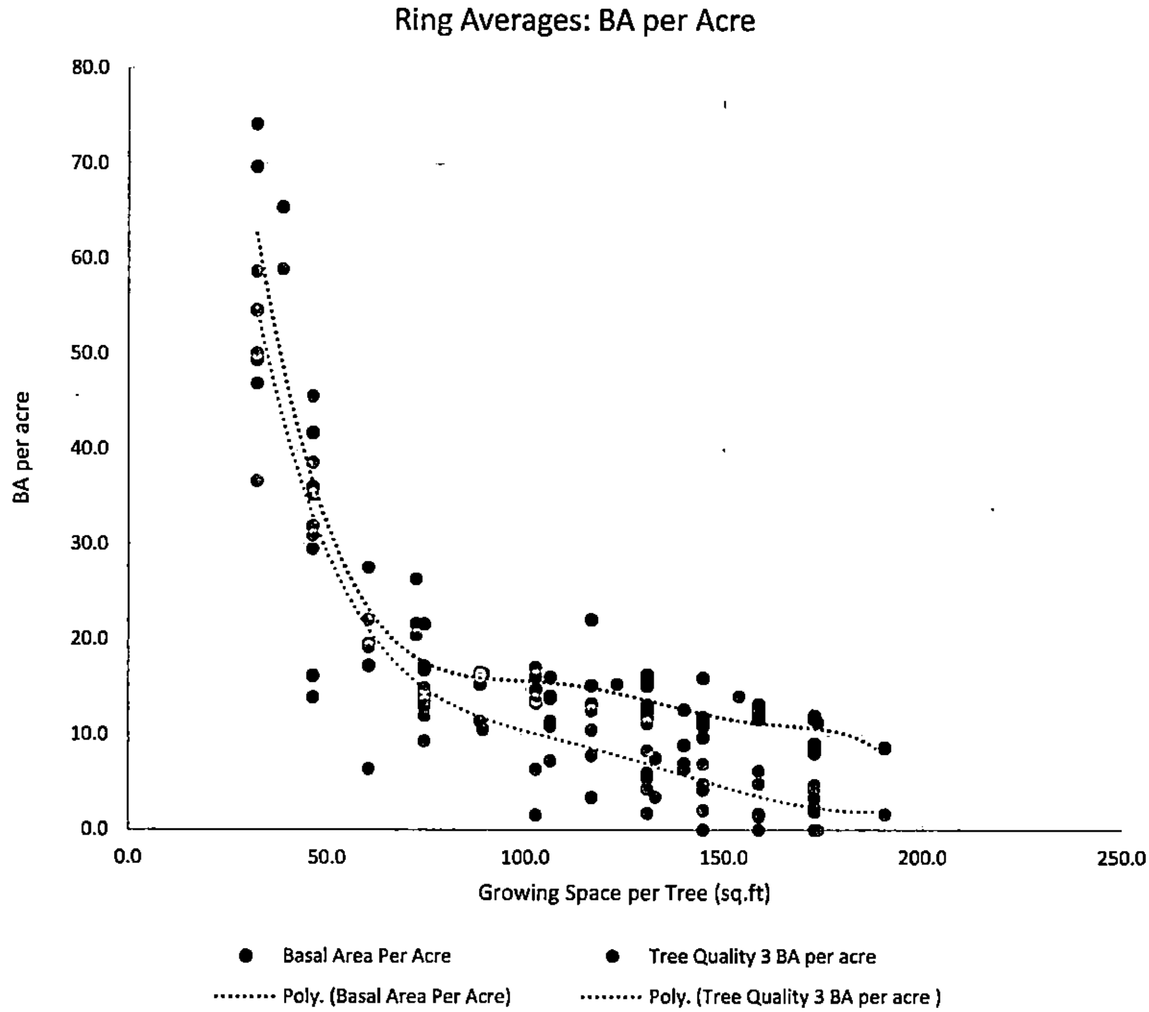


Figure 8. Tree metrics by growing space per tree

Displays basal area, DBH, dominant height, and average total height based on growing space per tree. Higher trees-per-acre values correspond to lower growing space per tree.

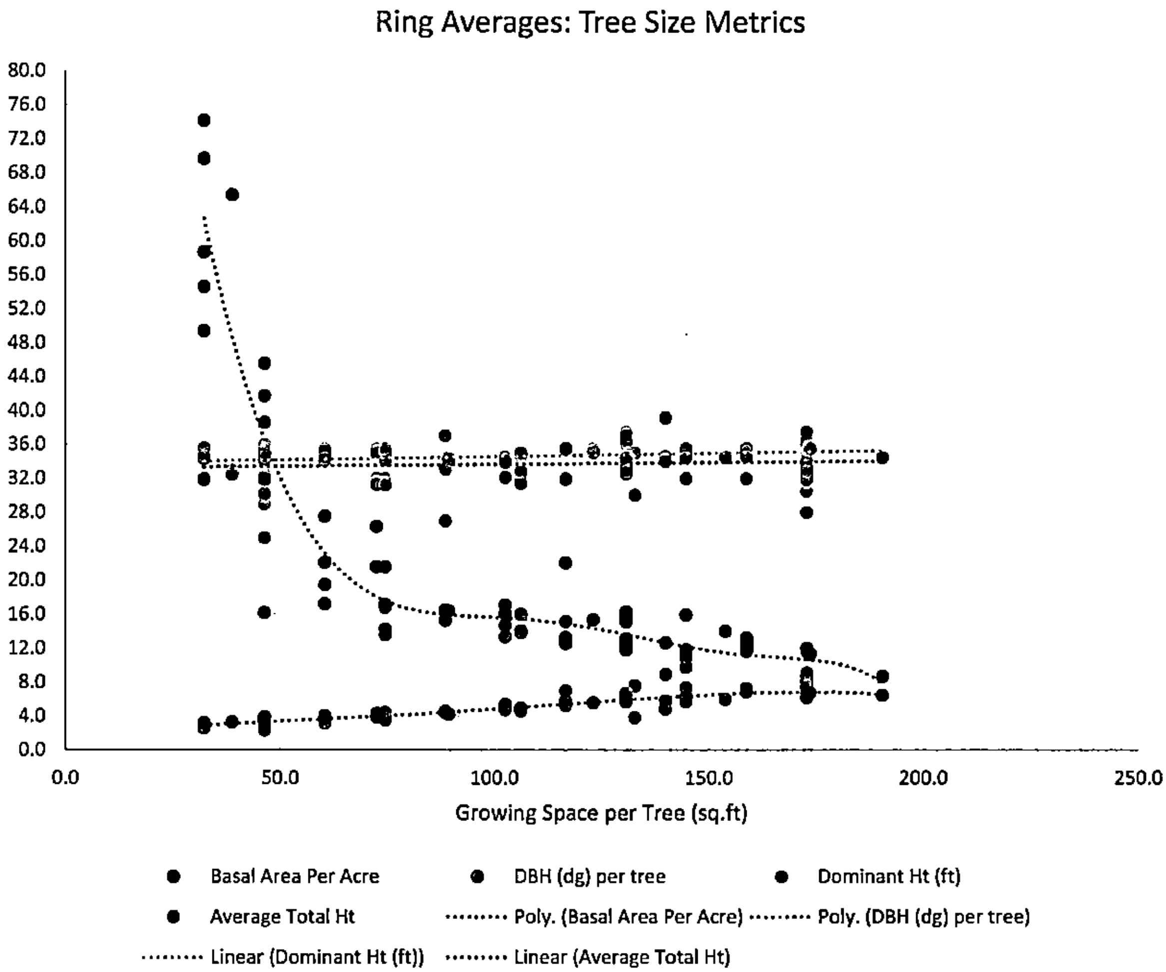
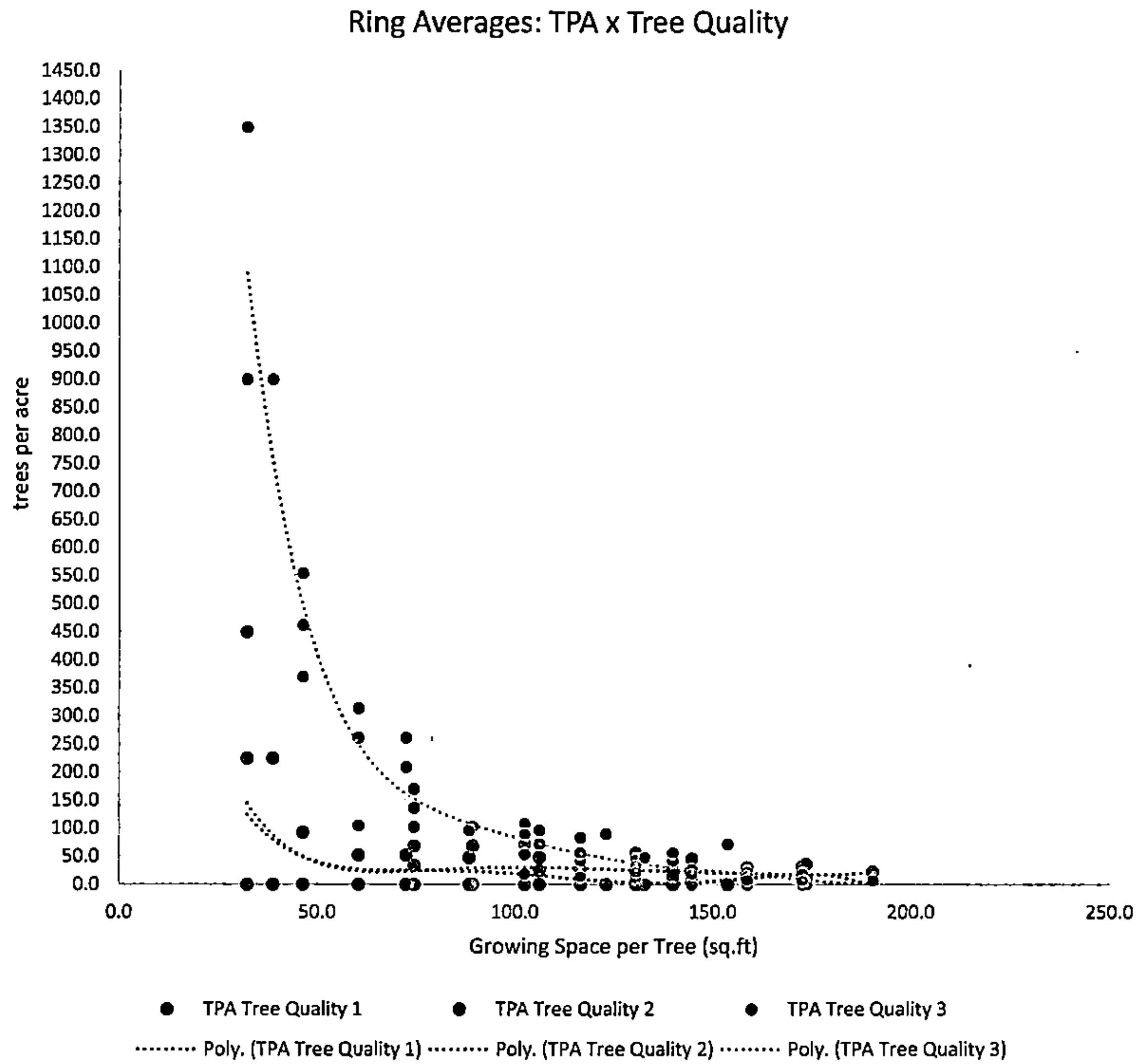


Figure 9. Tree quality by growing space per tree

1: Always pulpwood 2: Potential sawtimber 3: Definite sawtimber



Planted Loblolly Pine

Two plantation spacings were chosen to investigate the effects of planting density on short-rotation loblolly pine growth for a single genotype (007056.LD); 1082 trees per acre and 1452 trees per acre. 146.7 acres were planted at the 1082 density and 142.6 acres were planted at the 1452 density. Location of planting sites can be found in Appendix 1, Overview Map. These areas were established in February 2011.

Observed living trees during the 2018 inventory were below expectations based on their original planting densities. To develop estimates from these data that reflect what we think could be expected in the future from planting at these densities, the Nelder plot results were used to adjust these measurement data. At this time it is unclear whether the low observed survival was due to factors at time of planting (poor planting quality, issues with seedlings, actual planting density) or factors since planting (losses from natural causes).

Results from both measured data (indicated by an M) and Nelder-adjusted data (indicated by an N) are displayed in the following figures.

Consideration was also given to the possibility of converting a biomass management regime (one with no thinning prior to final harvest) to a traditional timber management regime with two thinnings and a final harvest. Yields from the following two scenarios were projected from the 2018 measurement data:

- Thinning at ages 14 and 22 with a final harvest at age 30, and
- Thinning at ages 16 and 26 with a final harvest at age 32.

<u>Figure 10. Greenweight mean annual increment</u>

Displays growth rate in green tons per acre per year at both planting densities (1082, 1452 TPA) and for both measured (M) and Nelder-adjusted (N) data.

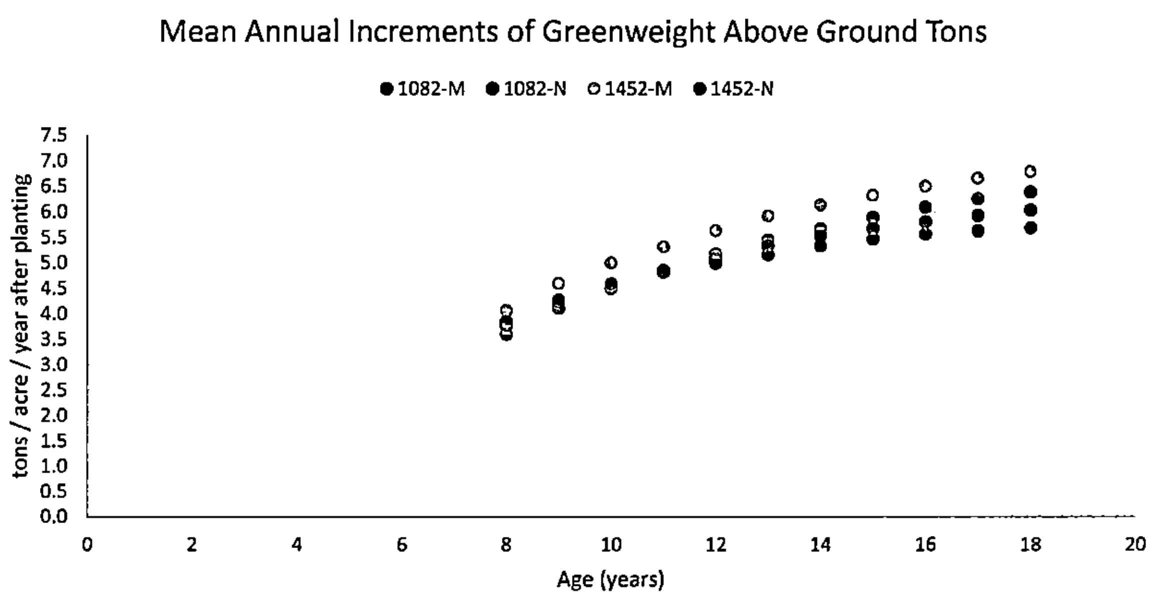


Figure 11. Dryweight mean annual increment

Displays growth rate in oven-dry tons per acre per year at both planting densities (1082, 1452 TPA) and for both measured (M) and Nelder-adjusted (N) data.

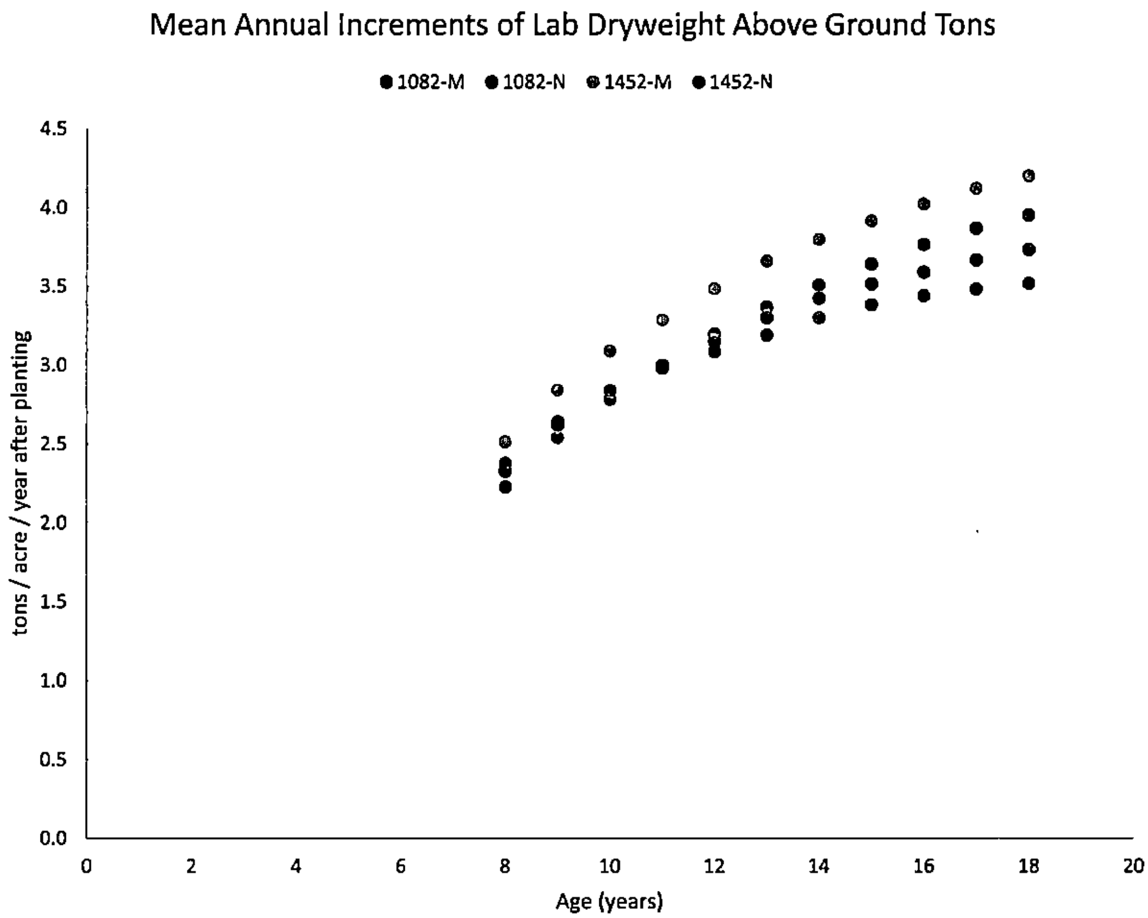


Table 2. Projected biomass yields at selected ages

Displays green weight of total biomass, oven-dry weight of bark-only biomass, oven-dry weight of wood-only biomass, and oven-dry weight of total biomass, at selected ages.

Calculations include both planting densities (1082, 1452) and for measured (M) and Nelder-derived (N) projections. All values are in tons per acre.

Scenario StandNumber	AGE Inv.age	Biomass (GreenWeight) biomassGW.tonspa	Bark Biomass (DryWeight) biomassDWBark.tonspa	Wood Biomass (DryWeight) biomassDWWood.tonspa	Total Biomass (DryWeight) biomassDWWoodandBark.tonspa
1082-M	12	62.1	5.0	33.4	38.4
1082-M	14	79.4	6.4	42.7	49.1
1082-M	16	97.5	7.9	52.5	60.3
1082-N	12	61.1	4.9	32.9	37.8
1082-N	14	77.5	6.2	41.7	48.0
1082-N	16	92.9	7.5	50.0	57.5
1452-M	12	67.7	5.5	36.4	41.9
1452-M	14	86.0	6.9	46.3	53.2
1452-M	16	104.1	8.4	56.0	64.4
1452-N	12	59.9	4.8	32.2	37.1
1452-N	14	74.7	6.0	40.2	46.2
1452-N	16	89.0	7.2	47.9	55.1

Table 3. Timber conversion projected yields, thin at ages 14 and 22 with final harvest at age 30

Displays merchantable weight removed at each thin age and final harvest for both planting densities (1082, 1452) and for measured (M) and Nelder-derived (N) projections. All values are in tons per acre, green weight basis.

Scenario StandNumber	AGE Inv.age	Total Removed merch.tonspa	Pulp Removed pulp.tonspa	Chip'n Saw Removed cns.tonspa	Sawtimber Removed saw.tonspa	TopwoodRemoved top.tonspa
1082-M	14	44.3	40.4	2.1	0.0	1.8
1082-M	22	77.9	59.0	12.5	0.0	6.3
1082-N	14	47.1	47.1	0.0	0.0	0.0
1082-N	22	83.8	83.8	0.0	0.0	0.0
1452-M	14	52.8	47.9	2.7	0.0	2.3
1452-M	22	95.2	74.4	13.7	0.0	7.1
1452-N	14	41.5	40.9	0.0	0.0	0.6
1452-N	22	90.4	90.4	0.0	0.0	0.0
1082-M	30	136.3	22.4	64.3	12.8	36.8
1082-N	30	141.7	40.0	60.3	0.0	41.4
1452-M	30	173.7	32.2	77.5	16.0	48.0
1452-N	30	193.0	115.0	46.2	0.0	31.8

Table 4. Timber conversion projected yields, thin at ages 16 and 25 with final harvest at age 32

Displays merchantable weight removed at each thin age and final harvest for both planting densities (1082, 1452) and for measured (M) and Nelder-derived (N) projections. All values are in tons per acre, green weight basis.

Scenario StandNumber	AGE Inv.age	Total Removed merch.tonspa	Pulp Removed pulp.tonspa	Chip'n Saw Removed cns.tonspa	Sawtimber Removed saw.tonspa	TopwoodRemoved top.tonspa
1082-M	16	49.7	45.8	2.1	0.0	1.8
1082-M	25	82.1	41.6	25.8	0.0	14.7
1082-N	16	47.5	47.5	0.0	0.0	0.0
1082-N	25	73.6	64.7	4.8	0.0	4.1
1452-M	16	54.6	49.7	2.7	0.0	2.3
1452-M	25	84.7	44.2	25.6	0.0	14.9
1452-N	16	43.3	42.7	0.0	0.0	0.6
1452-N	25	91.0	91.0	0.0	0.0	0.0
1082-M	32	164.1	23.2	83.5	18.3	39.1
1082-N	32	123.5	50.2	49.5	0.0	23.8
1452-M	32	176.0	25.1	87.9	22.3	40.7
1452-N	32	157.7	130.0	16.7	0.0	11.0

Planted Hardwood

Hardwood plantations containing cottonwood, hybrid poplar, aspen, sweetgum, and black willow were established on both upland and bottomland sites. The upland sites were planted in 2011 and the bottomland sites were planted in 2012. A variety of genotypes within each species group were planted - 37 unique genotypes from 4 different producers were installed at the SC8 site.

While inventory field data were collected by genotype and site type, this report merges all data within each species group and site type into a single stratum. The purpose was to investigate yield within each species group, on an operational level, and not to prepare genotype-level calculations.

Yield projection only exists for cottonwood group as models were either not available or had suspect results for hybrid poplar, aspen, sweetgum, and black willow.

Location of general planting sites is in Appendix 1, Overview Map, and species-group specific planting sites can be found in the accompanying cruise maps.

Figure 12. Trees per acre by site type and species group

Displays trees per acre by species group and site type, for both natural and planted trees.

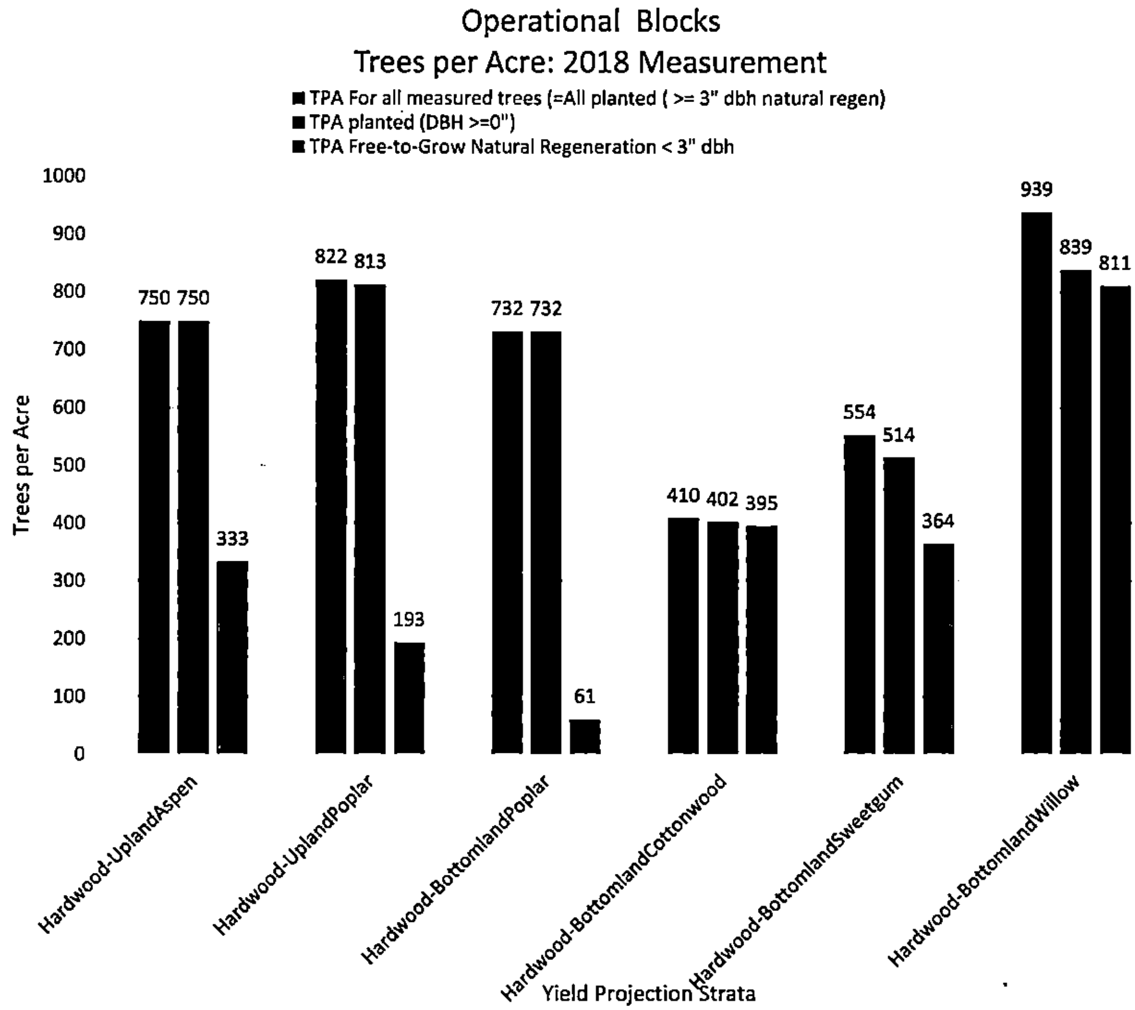


Figure 13. Basal area, average total height, and dominant height

Displays basal area and height metrics by species group and site type.

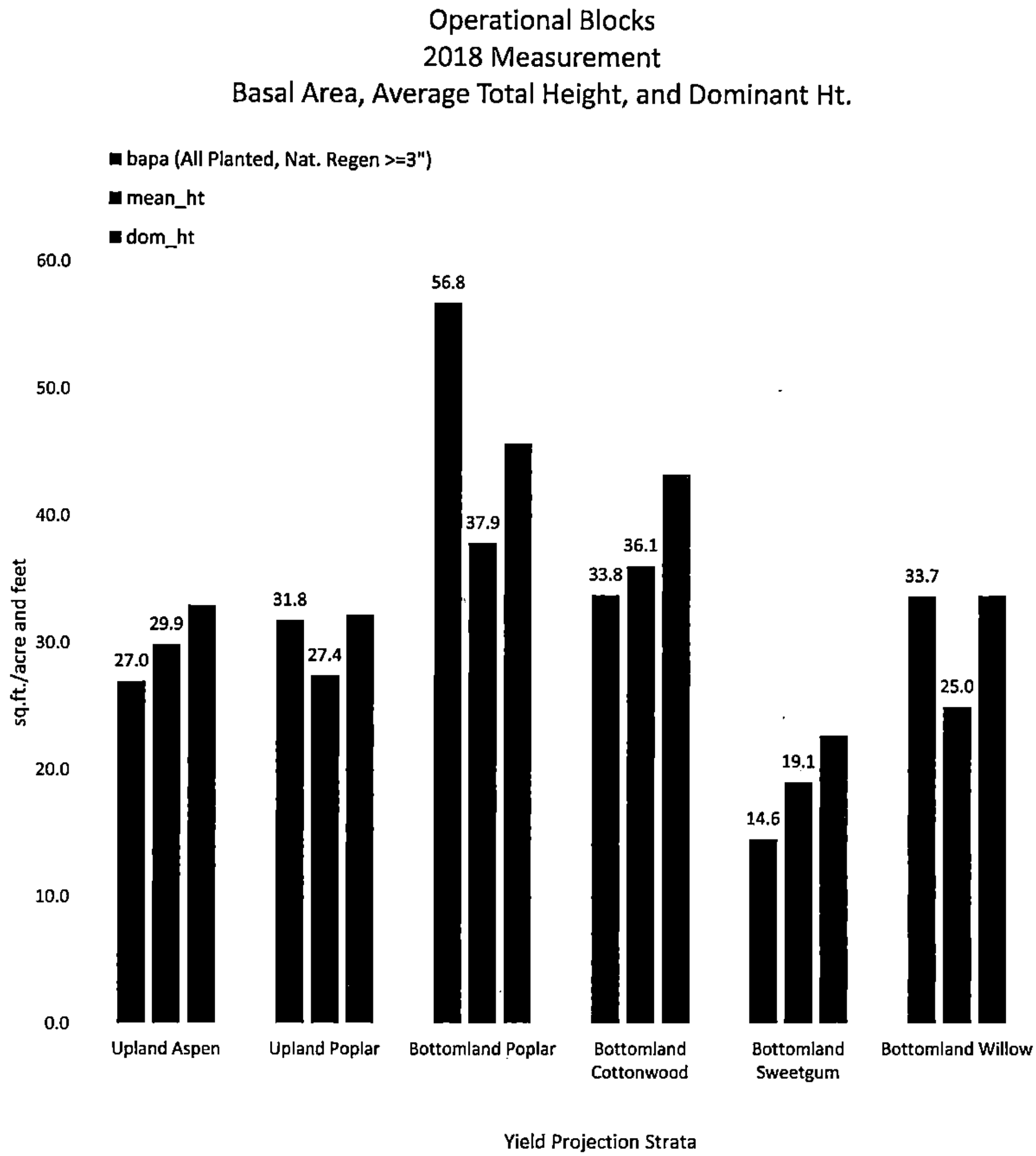


Figure 14. Green weight and dry weight biomass yields

Displays tons per acre both green and dry by species group and site type.

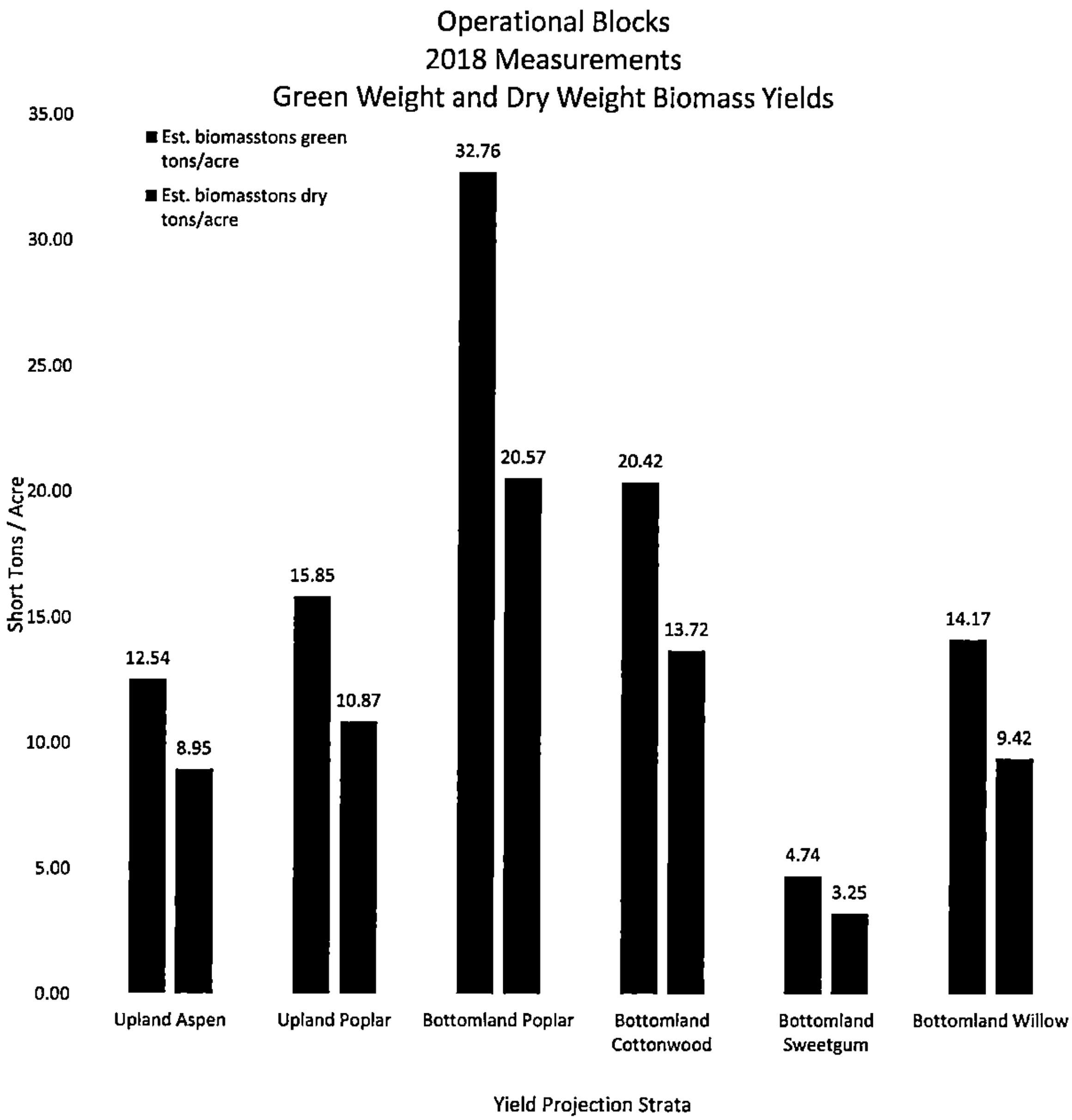


Figure 15. Green weight change in values from 2015 measurement

Displays the change in biomass green weights since the 2015 inventory.

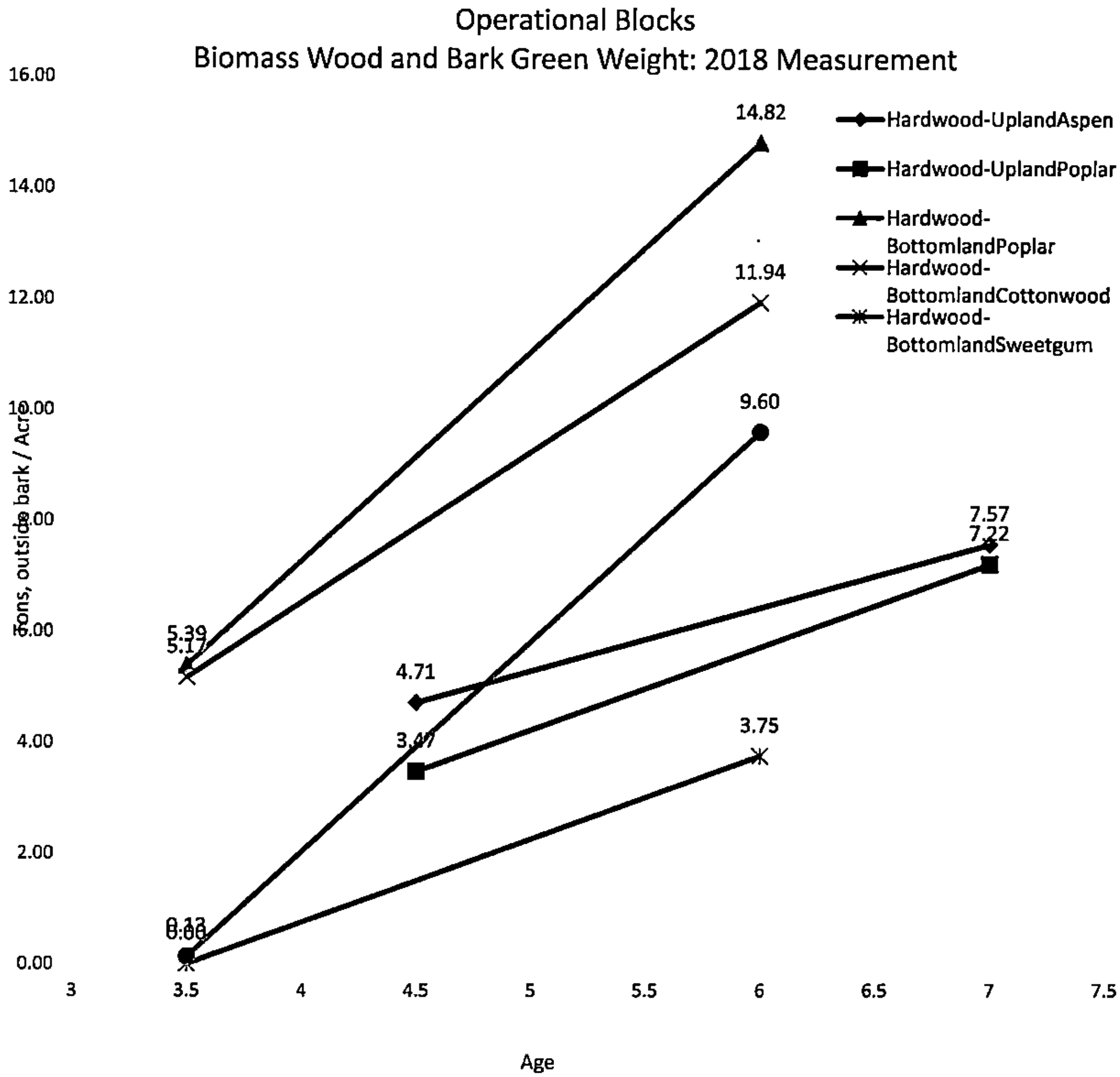


Figure 16. Dry weight change in values from 2015 measurement

Displays the change in biomass dry weights since the 2015 inventory.

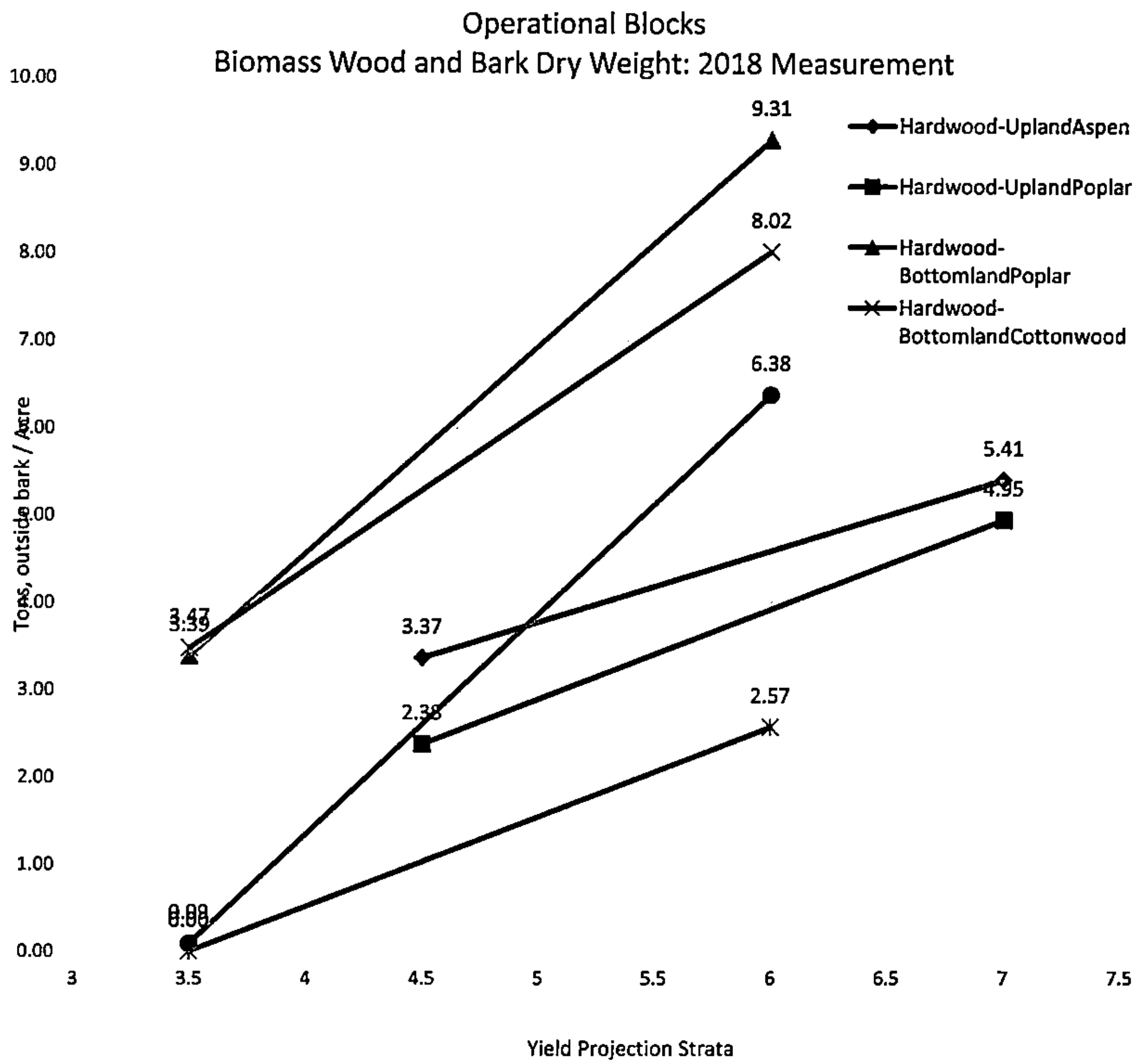


Figure 17. Projected cottonwood dry weight outside bark

Displays the dry weight projected yields for cottonwood through age 10 for two initial data points and two projection methods: 2015 inventory data, 2018 inventory data, and revised projections based on actual growth observed between 2015 and 2018.

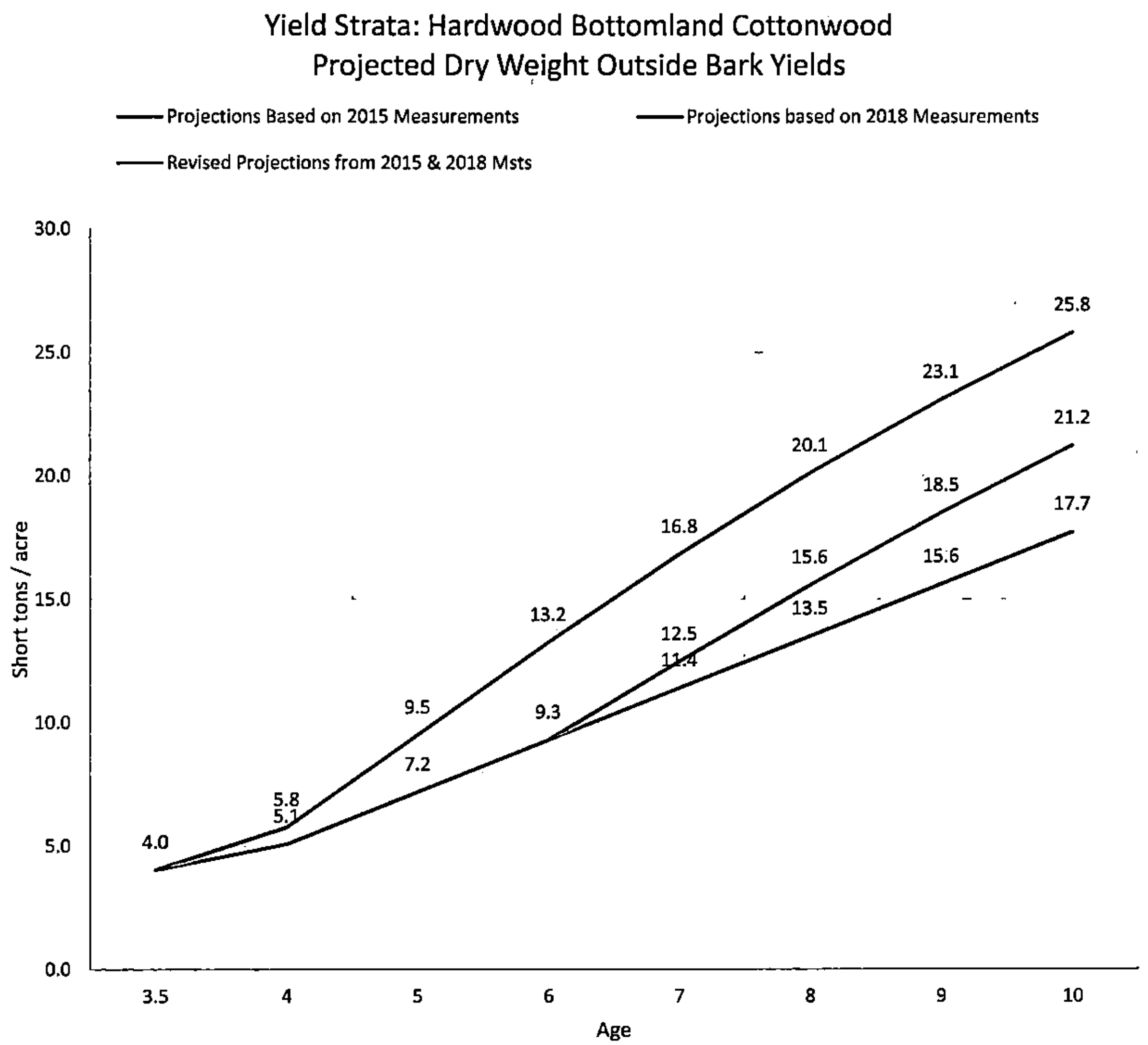


Figure 18. Projected cottonwood dry weight outside bark mean annual increment

Displays the projected dry weight MAI through age 10 for two initial data points and two projection methods: 2015 inventory data, 2018 inventory data, and revised projections based on actual growth observed between 2015 and 2018.

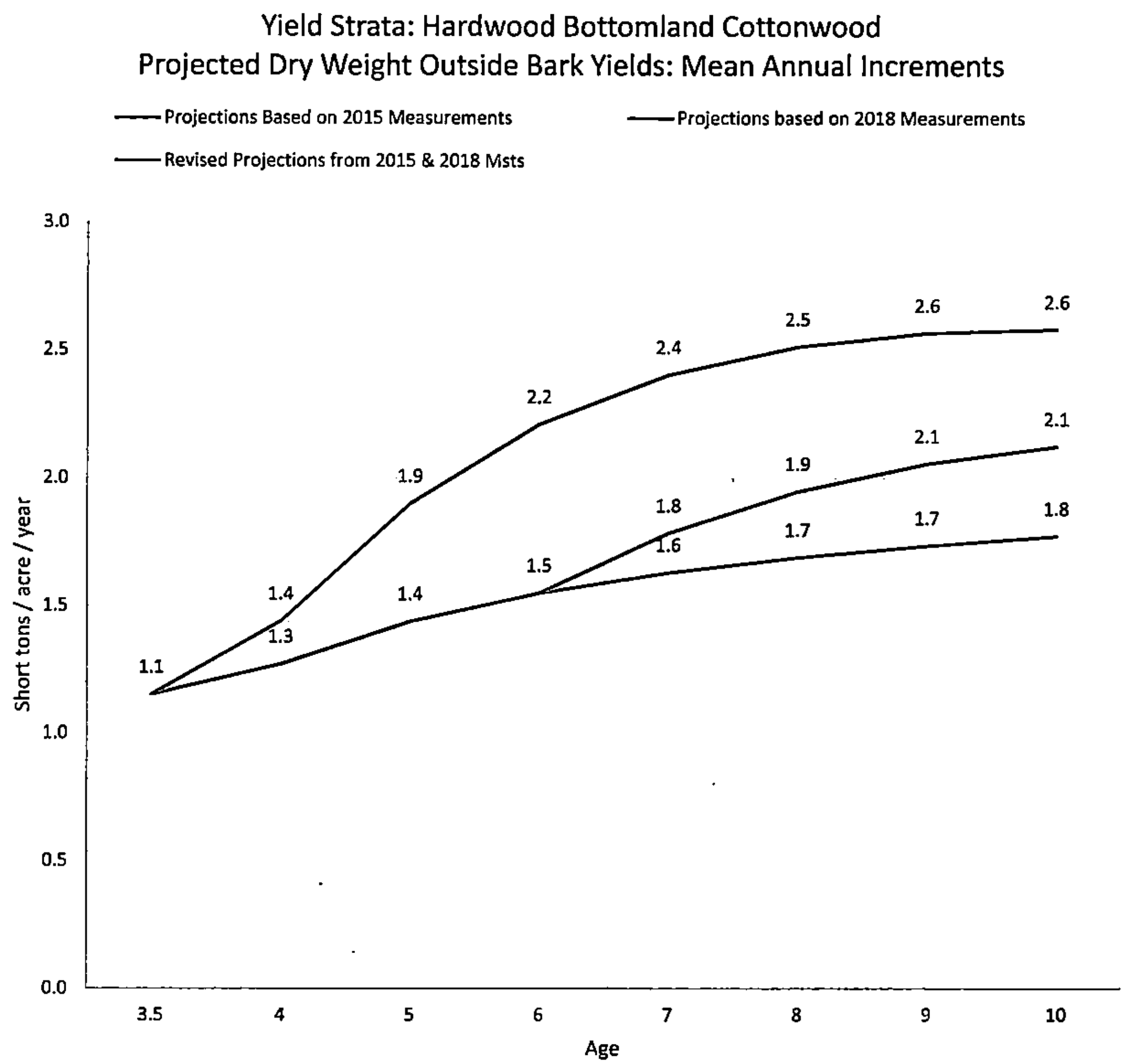


Figure 19. Projected cottonwood green weight outside bark

Displays the green weight projected yields for cottonwood through age 10 for two initial data points and two projection methods: 2015 inventory data, 2018 inventory data, and revised projections based on actual growth observed between 2015 and 2018.

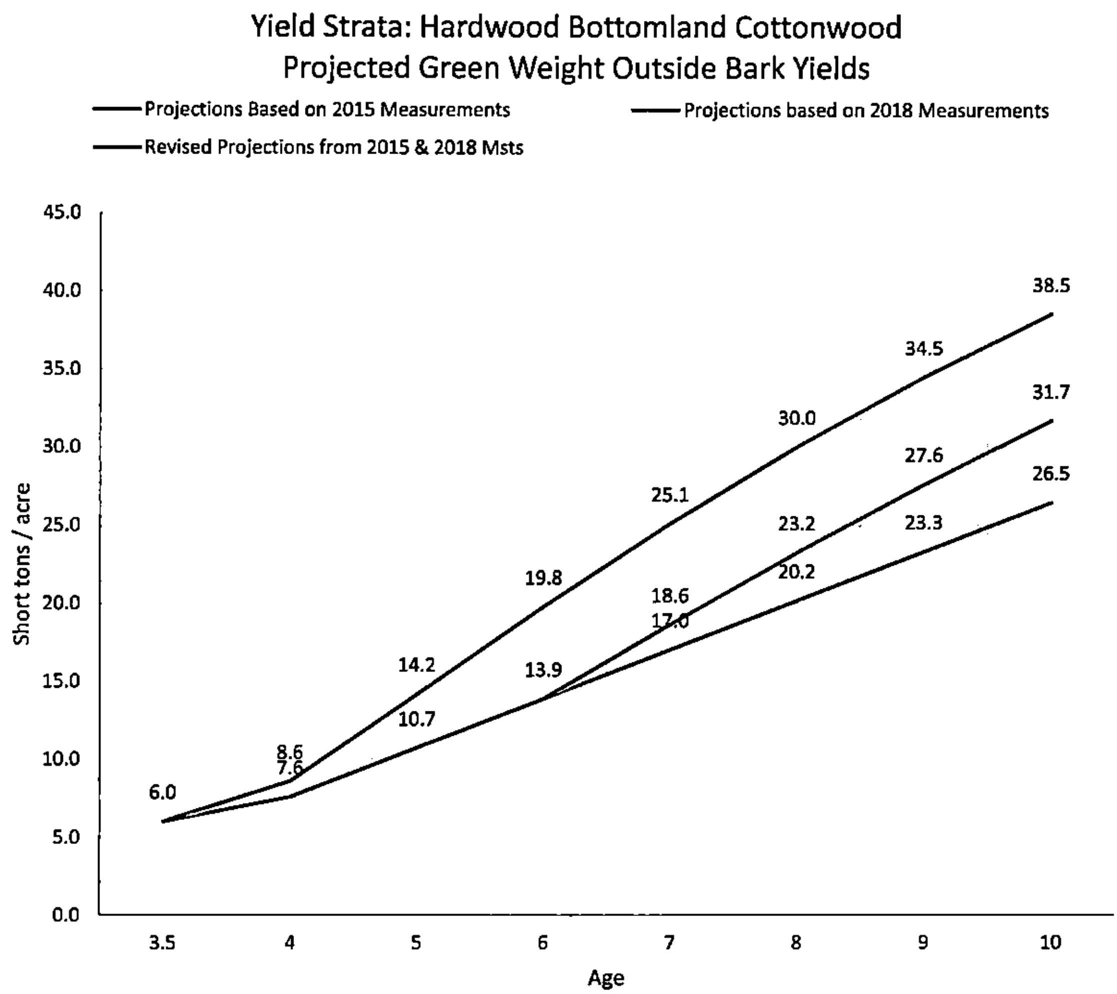
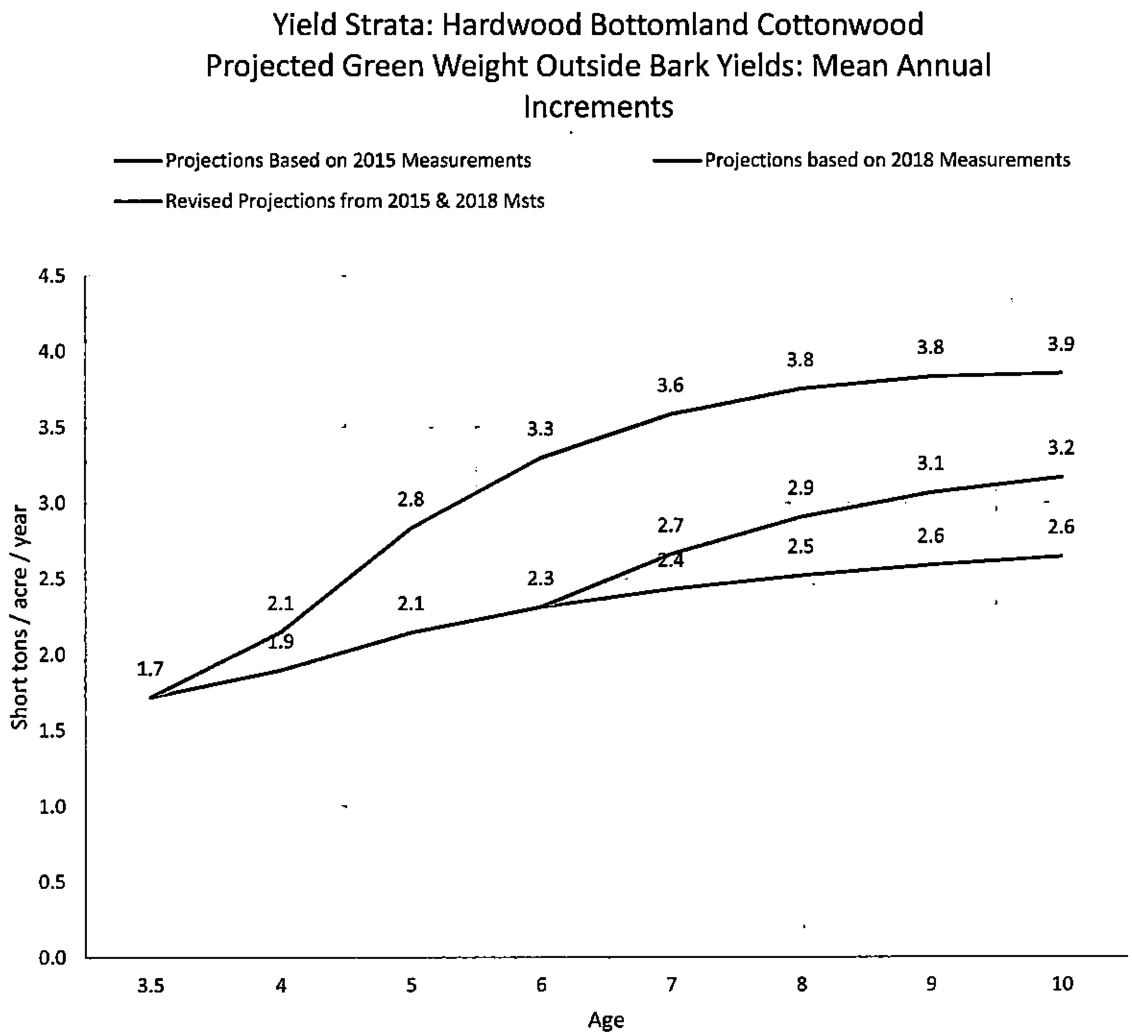


Figure 20. Projected cottonwood green weight outside bark mean annual increment

Displays the projected green weight MAI through age 10 for two initial data points and two projection methods: 2015 inventory data, 2018 inventory data, and revised projections based on actual growth observed between 2015 and 2018.



Analysis and Conclusions

Data analysis was restricted to biometrics only; no specific economic analyses were performed. Final conclusions and operational recommendations should consider seedling costs, establishment and maintenance cost differences over multiple rotations, and operational factors, not the least of which is harvesting cost.

Loblolly Nelder

While the primary purpose of a Nelder plot is to investigate the effects of tree spacing on growth, the SC8 Nelder implementation also allowed investigation of growth difference between 6 different genotypes.

Height and Diameter by Genotype

While the AG Varietal Container expressed the tallest height (35.50') and the AG MCP Container expressed the shortest height (32.12'), there was no significant difference in height growth across all genotypes. Furthermore, tree age was young enough (7.5 years) that long-term height growth potential between genotypes may not have had time to be fully expressed.

Similarly, DBH variation across genotypes expressed no significant difference; while the CF Varietal Container had the largest DBH (3.94") and CF VarietalQ Container had the smallest (3.40"), observed variation cannot be definitively attributed to genotype at this young age.

Stocking by Genotype

Stocking, a function of trees per acre (TPA) and basal area per hectare (which is additionally based on tree diameter), also expressed no significant differences among genotypes. One interesting observation, however, was that the genotype with the lowest TPA, CF VarietalL Container, did not have the lowest basal area; indicating that this genotype was able to efficiently capture the increased growing room per tree in accelerated diameter growth.

Tree Weight by Genotype

Four weight metrics were examined for each genotype: entire tree (main stem, limbs, needles) dry weight, merchantable (main stem of trees greater than 5" DBH) green weight, main stem (all trees, regardless of DBH) green weight, and entire tree green weight.

AG 2ndGen Container expressed the highest values for weight measurements across all measurement categories. With the exception of merchantable green weight, ranking between genotypes remained constant for all weight categories (the AG Varietal Container genotype expressed the highest merchantable weight).

Tree Weight by Tree Quality

All Nelder plot trees were evaluated for their future timber quality suitability. Categories included 1 - always pulpwood, 2 - potential sawtimber, and 3 - definite sawtimber. These measurements can assist in determining the best genotype to select for crops where there may be a future timber (as opposed to biomass) management regime conversion. The measured value was total green weight.

The AG 2ndGen Container expressed the highest value across all quality categories. This genotype maintained its top rank for quality 3, was ranked a very close second for quality 2, but fell to rank 4 for quality 1 (the WY 2ndGen Bareroot took top ranking for quality 1 trees).

Weight by Trees per Acre

Four weight metrics were examined for all genotypes combined across the range of trees per acre: main stem green weight, entire tree green weight, merchantable stem green weight, and entire tree dry weight.

As expected main stem green weight, entire tree green weight, and entire tree dry weight increased more or less linearly across the range of 39 TPA at the Nelder rim to 1,349 TPA at the core. Merchantable stem weight, however, decreased to zero from 39 TPA to roughly 300 TPA, then appeared again and started increasing around 700 TPA, peaked around 1,100 TPA, and again fell to zero around 1,400 TPA. This effect for merchantable stems can be attributed to trees being too small to qualify for merchantability at stocking levels of 300-700 TPA from inter-tree competition at age 7.5.

As stocking levels increase above 700 TPA the sheet number of trees provides for at least a few to be of merchantable size, but this effect peaks at extremely high densities (above 1,100 TPA) again due to inter-tree competition. Low densities (below 300 TPA) provide sufficient growing room for many trees to reach merchantable size, but the low numbers of overall trees at these reduced stocking levels limits total merchantable stem availability.

Weight by Seedling Type and Trees per Acre

Seedlings were combined into four different categories (varietal container, orchard-mix container, orchard mix bareroot, and mass-control pollinated container) based on production method and genetic lineage to investigate weight production across the range of planting densities.

All categories expressed more or less linear response to planting density; the more trees planted per acre, the higher the yield. Orchard-mix container trees expressed the largest values and orchard-mix bareroot the smallest. The mass-control pollinated trees exhibited the greatest change as planting density increased, moving from the lowest weight values at low densities to nearly as high as the orchard-mix container trees at high densities. Rankings of the other seedling categories were unchanged across the range of planting densities.

Basal Area and Tree Quality by Planting Density

Both overall basal area per acre and quality 3 (definite sawtimber) basal area was evaluated as growing space per tree (the inverse of trees per acre) changed. As growing space per tree increased both overall basal area and quality 3 basal area decreased (fewer trees available at wider spacings to provide basal area). At lower densities (more growing room per tree), however, quality 3 tree basal area decreased more rapidly than overall basal area; the result of inter-tree effects on tree form (widely spaced trees retain limbs longer and grow with more taper than closely spaced trees).

Tree Metrics by Growing Space per Tree

Changes to basal area per acre, DBH, dominant height, and average height as growing space increased was examined. As seen previously, basal area per acre decreased as growing space per tree increased. DBH increased roughly 100% from high density to low density stocking, while dominant height and average height remained relatively constant. These observations compare well with the concepts that height growth is relatively unaffected by stand density while diameter growth is significantly affected by stand density.

Tree Quality by Growing Space per Tree

The final metric analyzed was how tree quality changes as growing space per tree increases. Numbers of quality 1 (pulpwood only) and 2 (potential sawtimber) trees both started at about 150 TPA at high stand densities, decreased dramatically early in the curve, and flattened out and remained more or less constant through the lowest stand densities. As previously seen quality 3 trees followed the same general trend but with much higher numbers in where growing room was low and a much more dramatic fall-off as growing room increased.

Conclusions

The Nelder plot is an extremely effective tool in evaluating the effects of stand density on tree growth and somewhat less effective on evaluating differences between different genotypes, at least at young stand ages.

Considering only stand density, volume production increases in an essentially linear fashion as stand density increases. The implication is that, for biomass production, higher stand densities for short-rotation loblolly crops will yield significantly higher tonnages. We believe there will be a point of diminishing returns if economic factors (seedling and labor cost) are considered, and while an economic analysis was not performed this point will probably be reached between 800 and 1,000 trees per acre.

Considering only genotype, it is clear that expensive seedlings (containerized and/or varietal) do not perform at a level that justifies their cost in biomass crops and the more economical bareroot seedlings should be selected for such crops.

Planted Loblolly Pine

Two plantation spacings were chosen to investigate the effects of planting density on short-rotation loblolly pine growth for a single genotype (007056.LD); 1082 trees per acre and 1452 trees per acre. 146.7 acres were planted at the 1082 density and 142.6 acres were planted at the 1452 density.

Greenweight Mean Annual Increment

Green weight MAI (average growth per year) was projected for both spacings for the next 10 years, using as growth and yield model input both empirical (M) measurements at age 8 and Nelder-adjusted (N) data.

1082 (M) MAI starts out lower than 1452 (M) MAI at age 8 and continues to remain below 1452 (M) values through age 18. The curves for both planting densities parallel each other over the period (i.e. no significant relative change to each other).

Using Nelder-adjusted inputs, the 1452 (N) MAI curve again starts out above the 1082 (N) curve, but their positions are revered around age 11. From that point onward the 1082 (N) curve surpasses the 1452 (N) curve, and increases slightly relative to the 1452 (N) curve over the period.

Overall, the 1452 (M) data set had the highest MAI across the period.

Dryweight Mean Annual Increment

Dry weight MAI was also projected for both spacings and both data sets (measured and Nelder) for a 10 year period.

1082 (M) MAI starts out and remains below 1452 (M) MAI at all ages. 1082 (N) starts out below 1452 (N) MAI, but it surpasses the 1452 (N) projection around age 11 and increases at a slightly increasing rate over the 1452 (N) curve through age 18.

Considering both M and N model inputs, the 1452 (M) data once again remains the highest MAI across the period.

<u>Projected Biomass Yields</u>
Biomass yield projections assumed that no thinnings would occur and the entire stand would be harvested for biomass at some age at or before 16 years. Four metrics associated with har4evst were projected: green weight, bark-only dry weight, wood-only dry weight, and wood and bark dry weight.

The 1082 (M) projection yields fewer green tons per acre than the 1452 (M) projection at every age. Using Nelder-adjusted data, however, the 1082 (N) yields more green tons per acre at each age.

This relationship between the 1082 and 1452 planting densities (and M and N data sets) hold true for all weight measurements, wood and bark separate or combined.

<u>Timber Conversion Projections</u>
Thought was given the possibility that a loblolly pine biomass crop may be converted to a traditional timber management regime. Reasons for possible conversion are many; they include changing value of biomass markets, changing ownership objectives, or regulatory or taxation changes that affect a producers overall position in the marketplace.

Conversion of a biomass regime to a timber regime was modelled through thinning the biomass crop to a timber regime density at first thin, and then continuing as if it had been established as a timber regime. Two scenarios were modelled; thinning at ages 14 and 22 with a final harvest at age 30, and thinning at ages 16 and 25 with a final harvest at age 32.

Both plantation densities (1082 and 1452) and data sets (M and N) were evaluated.

Using the M data model input and the 14/22/30 scenario, the 1082 planting density produced fewer tons than the 1452 density, both overall and on a product-level basis. This same relationship held true for the N data input, except that the 1082 density produced slightly more topwood than the 1452 density. All M yields were lower than the corresponding N yields with the exception of topwood; in that product class the M yields were somewhat higher than the N yields.

Using the M data model input and the 16/25/32 scenario, the 1082 planting density again produced fewer tons than the 1452 density, both overall and in every product class. This same relationship held true for the N data input for pulpwood; however the 1082 yield surpassed the 1452 yield in every other product class.

Comparing the 14/22/30 scenario to the 16/25/32 scenario, the 1082 planting density produces fewer total tons than the 1452 planting density for the M data set, but produces more tons for the N data set.

Conclusions

Considering that projections for the M data set produce different results than the N data set, any conclusions drawn from the planted pine analysis may be subject to some dispute. However, we believe that the N data set more accurately reflects what would be observed in additional trials, and therefore it is appropriate to use that data set to develop conclusions. The reader is cautioned that this analysis does not factor in the relative establishment costs or economic value of different timber products, and only considers the ability of each planting density to produce wood.

Recommended planting density for biomass crops will depend to a large degree on planned harvest age. For rotations less than 11 years the projections suggest that a planting density of 1452 trees per acre will generate higher yields; rotations longer than 11 years would see some benefit to planting at the lower 1082 density. Recommended planting density for a potential timber regime conversion favors the 1082 planting density and the 14/22/30 management regime scenario.

In summary, the only time one might consider planting to the 1452 density is when the expected harvest age is less than 11 years and the possibility of adopting a timber regime is low. In all other instances maximum yield will be gained by planting to 1082 trees per acre.

Planted Hardwood

Hardwood plantations containing cottonwood, hybrid poplar, aspen, sweetgum, and black willow were established on both upland and bottomland sites. The upland sites were planted in 2011 and the bottomland sites were planted in 2012. 2015 and 2018 field measurements were analyzed for stand density, biomass yields, and change in growth from 2015 to 2018. In addition yields for the cottonwood group were projected out to age 10.

Basal Area, Average Height, Dominant Height

Of the 6 species/site groups, highest basal area, average height, and dominant height values were observed in bottomland poplar. On upland sites poplar had a higher basal area but lower average and total heights than aspen. The lowest values were found in bottomland sweetgum; its basal area was roughly 25% of poplar and heights were roughly 50% of those observed for poplar.

Comparing upland and bottomland poplar, the upland site had about half the basal area and 75% of the height of the bottomland site.

Green and Dry Weight Yields

Following the trend established by tree metrics, highest yields (green and dry) were observed with bottomland poplar. Considering upland vs. bottomland sites, poplar again had the highest green and dry yields. The worst producer was again bottomland sweetgum; its yield was roughly 14% of the poplar yield.

Comparing upland and bottomland poplar; the upland site produced roughly half what the bottomland site produced.

Yield Changes from 2015 to 2018

For both green and dry weights, bottomland poplar once again ranked first. Bottomland cottonwood was a close second, followed by upland aspen, upland poplar, and sweetgum. Black willow and sweetgum had similar yields in 2015. However, the biomass growth rate in the black willow block was significantly greater than all of the other blocks suggesting that in the next several years black willow biomass may equal that in the cottonwood and hybrid poplar blocks.

Cottonwood Green and Dry Weight Projections

Yield projections through age 10 were prepared for two initial data points and two projection methods: 2015 inventory data, 2018 inventory data, and a revised projection based on actual growth from between 2015 and 2018.

The 2015 initial data had the highest projected yields for both green and dry material at all ages, followed by the projections based on the 2018 measurement. The revised projection using the actual 2015 and 2018 growth rate is lower. Projected yield increases (dry and green) between age 6 and 10 were 95% for the 2015 data, 127% for the 2018 data, and 90% for the revised data. The lower projections from both the 2018 measurement and the revised projections can be partly explained by "operational fall down" meaning that projection models are often based on experimental plots under tightly controlled conditions.

Cottonwood Green and Dry MAI Projections

MAI projections through age 10 were prepared for two initial data points and two projection methods: 2015 inventory data, 2018 inventory data, and a revised projection based on actual growth from between 2015 and 2018.

The 2015 initial data had the highest MAI for both green and dry material at all ages, followed by the 2018 initial data and finally the revised data based on actual growth. Projected MAI increases (dry and green) between age 6 and 10 were 18% for the 2015 data, 39% for the 2018 data, and 13% for the revised data. MAI increase gradually levels off as tree age approaches 10 years; most pronounced for the 2015 data, somewhat less for the 2018 data, and then returning to the 2015 trend for the revised data.

Conclusions

The data clearly shows that hybrid poplar, planted on bottomland sites, is the best biomass producer. Second best is bottomland cottonwood (roughly 60% of poplar production). Poplar is also the tree of choice to plant on upland sites for biomass production, but upland poplar only produces about half what bottomland poplar can produce (and 75% of bottomland cottonwood production).

Given the high establishment costs for hardwood plantations in general, and biomass crops in particular, planting anything other than hybrid poplar or cottonwood on bottomland sites is not recommended.

Future Management

2018 marks the end of the SC8 biomass project in its current form. A great deal of time, effort, and expense has gone into establishing and managing this project, and maintaining the study sites for potential future evaluation will take a minimum of time and expense.

Loblolly Nelder

Long-term maintenance will only require periodic (2-3 times per year) qualitative inspections to observe tree health and site integrity. The area should be protected from harvesting activities in adjacent stands at all times (a protective buffer of 1-1.5 times the adjacent tree heights is suggested).

Consideration should be given to an additional formal inventory in 2021 to determine if any additional differentiation between genotypes has occurred and to verify and calibrate the growth and yield models for projecting future yields.

Planted Loblolly Pine

With significant acreages in both planting densities, a reduced study site size is suggested to maintain the viability of potential future measurements. 10 acres in each of the planting densities could be retained and the remaining acreage converted to a traditional timber regime. Conversion of the majority of each density to a timber regime will simplify overall tract management and provide an enhanced revenue stream with more acres being available for timber production.

In the event fuelwood markets improve and contractors become available, consideration should be given to fuelwood harvest of half the retained study sites to obtain empirical biomass yields. Empirical data could then be compared to modelled yields with an eye towards improving models for high-density, short rotation loblolly biomass crops.

Consideration should be given to an additional formal inventory in 2021 to determine if any additional differentiation between planting densities has occurred.

Planted Hardwood

As with the Nelder plot, long-term maintenance will only require periodic (2-3 times per year) qualitative inspections to observe tree health and site integrity. The areas should be protected from harvesting activities in adjacent stands at all times (a minimal protective buffer of 15-20 feet is suggested).

In the event fuelwood markets improve and contractors become available, consideration should be given to fuelwood harvest of half the study sites to obtain empirical biomass yields. Empirical data could then be compared to modelled yields with an eye towards improving models for upland and bottomland hardwood biomass crops. Furthermore, the harvest would provide an opportunity to investigate natural regeneration associated with coppice and root suckering and comparative yields in future rotations.

Consideration should be given to an additional formal inventory in 2021 to investigate yields at age 10 (upland plantings) and age 9 (bottomland plantings).

Appendix 1 – Job Control Specifications, SC8 2018 Biomass Inventory

Job Control Specifications
SC8 2018 Biomass Inventory

Hardwood Plantations

Plot Size & Layout

Fixed radius plots (1/50th acre, 16.65' radius) will be used to measure sample trees in upland and bottomland hardwood plantations. Plots will be located on tract maps by AFM staff prior to starting fieldwork. Plot location data files suitable for Garmin GPS units or field computers with Solo software will be provided

Marking Sample Plots

The center of each plot was previously located during the 2015 inventory and should be marked with a white PVC stake. Plot centers will be re-established/marked as needed by ensuring the PVC stake is in place and hanging flagging at eye level near plot center. The plot number and cruiser initials will be marked on the flag at plot center. These will continue to be permanent sample plots. Tally will start with the **first planted tree to the north** and continue clockwise; this tree will also be flagged.

Tree Measurements

The following characteristics will be recorded for each planted hardwood lying within the plot:

- Species: From the stand lister on cruise maps
- Genotype: From the stand lister on cruise maps
- Diameter: DBH to nearest tenth of an inch. Use of calipers instead of a D-tape is recommended. For planted hardwoods not yet having DBH ground-line diameter (GLD) will be recorded instead of DBH (GLD values will be recorded in the GLD column on tally sheets).
- Height: Total height to nearest foot

Number of competing, free-to-grow (FTG) natural trees found on sample plots will be recorded by:

- Species (will generally be a pine species, cottonwood, sweetgum, or red maple but other species may be present). Species codes include:
  - A: Ash
  - Asp: Aspen
  - C: Cottonwood
  - P: Poplar (any *Populus* species)
  - Pn: Pine (any *Pinus* species)
  - Rm: Red maple
  - S: Sweetgum
  - Syc: Sycamore
  - Yp: Yellow-poplar
  - Additional species can be added if needed so long as their identifier is uniform across all plots.
- Number occurring on the sample plot. No more than 25 individuals of a particular species will be recorded
- FTG is defined as being in the general level of the canopy as planted trees. For gaps or holes in the planted canopy FTG trees are those wherein a +/- 30-degree cone extending from the terminal bud of the natural tree does not intersect the out canopy edge of planted trees. Use your judgement; in certain situations trees not meeting the exact FTG spec may be tallied. The goal is to provide an indication of natural trees that will survive, thrive, and present potential competitive pressures on planted trees.

Tally sheets have been provided. Plot level data (Block ID, Plot #) is not required for each tree but only once per plot. Block IDs and plot numbers are preassigned and must be entered as indicated on cruise maps.

Loblolly Nelder (Refer to attached Pine Nelder Detail Map)

Each tree within the Nelder plot has been pre-identified via the attached schematic; that naming convention will be used for identifying sample trees. Data to be collected includes:

- Section Identifier: per the attached schematic
- Row Identifier: per the attached schematic
- Tree Identifier: per the attached schematic
- DBH: nearest tenth of an inch <u>for every tree</u>
- Height: total height to nearest foot for <u>tree numbers 2, 5, 8, and 11</u> within each row. If the designated tree is dead (no longer present) then the next-higher tree number will be measured.

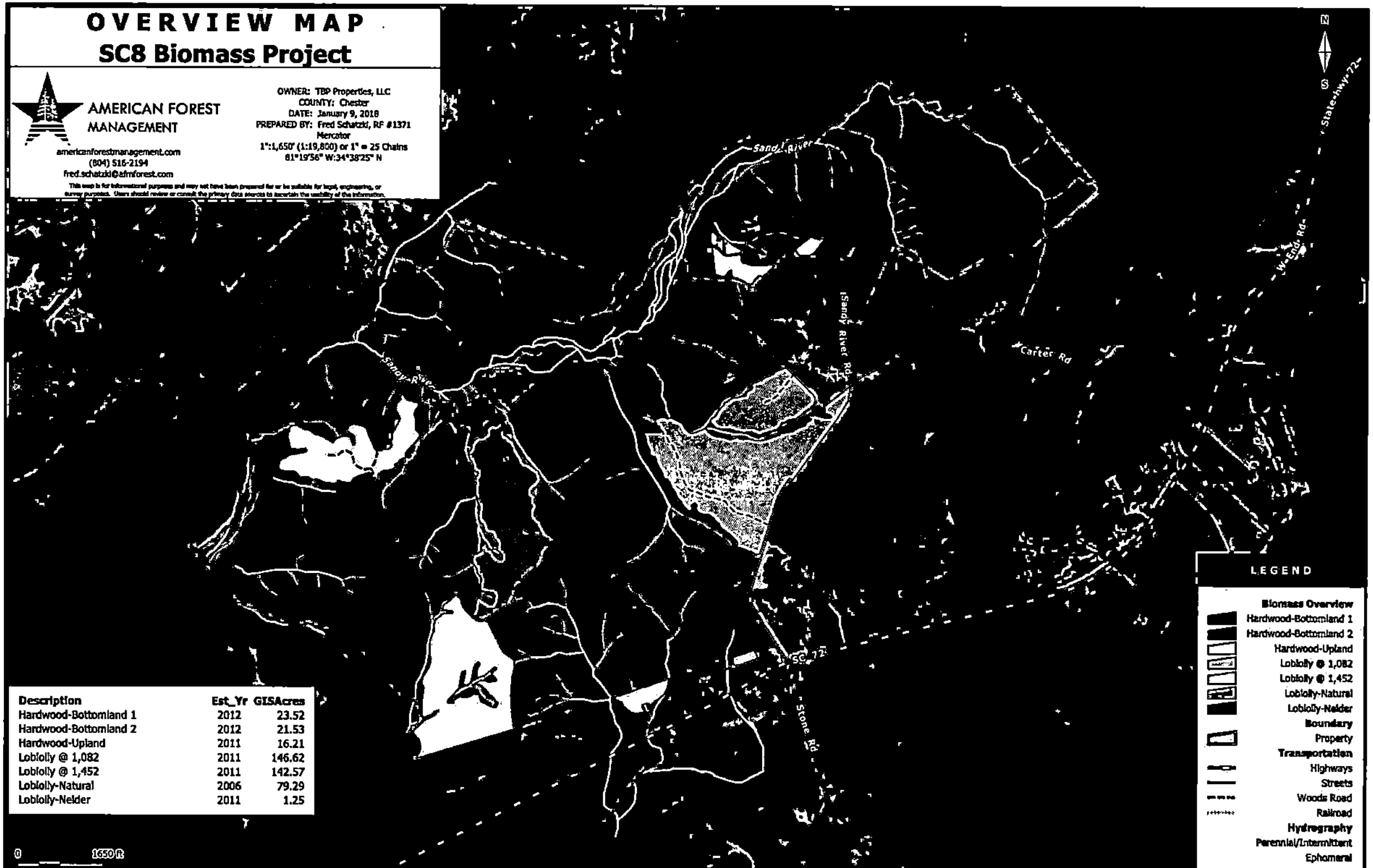
A sample tally sheet has been attached.

OVERVIEW MAP
SC8 Biomass Project

AMERICAN FOREST MANAGEMENT
americanforestmanagement.com
(804) 516-2194
fred.schatzki@afmforest.com

OWNER: TBP Properties, LLC
COUNTY: Chester
DATE: January 9, 2018
PREPARED BY: Fred Schatzki, RF #1371
Mercator
1":1,650' (1:19,800) or 1" = 25 Chains
81°19'56" W:34°38'25" N

This map is for informational purposes and may not have been prepared for or be suitable for legal, engineering, or survey purposes. Users should review or consult the primary data sources to ascertain the usability of the information.



Description	Est_Yr	GISAcres
Hardwood-Bottomland 1	2012	23.52
Hardwood-Bottomland 2	2012	21.53
Hardwood-Upland	2011	16.21
Loblolly @ 1,082	2011	146.62
Loblolly @ 1,452	2011	142.57
Loblolly-Natural	2006	79.29
Loblolly-Nelder	2011	1.25

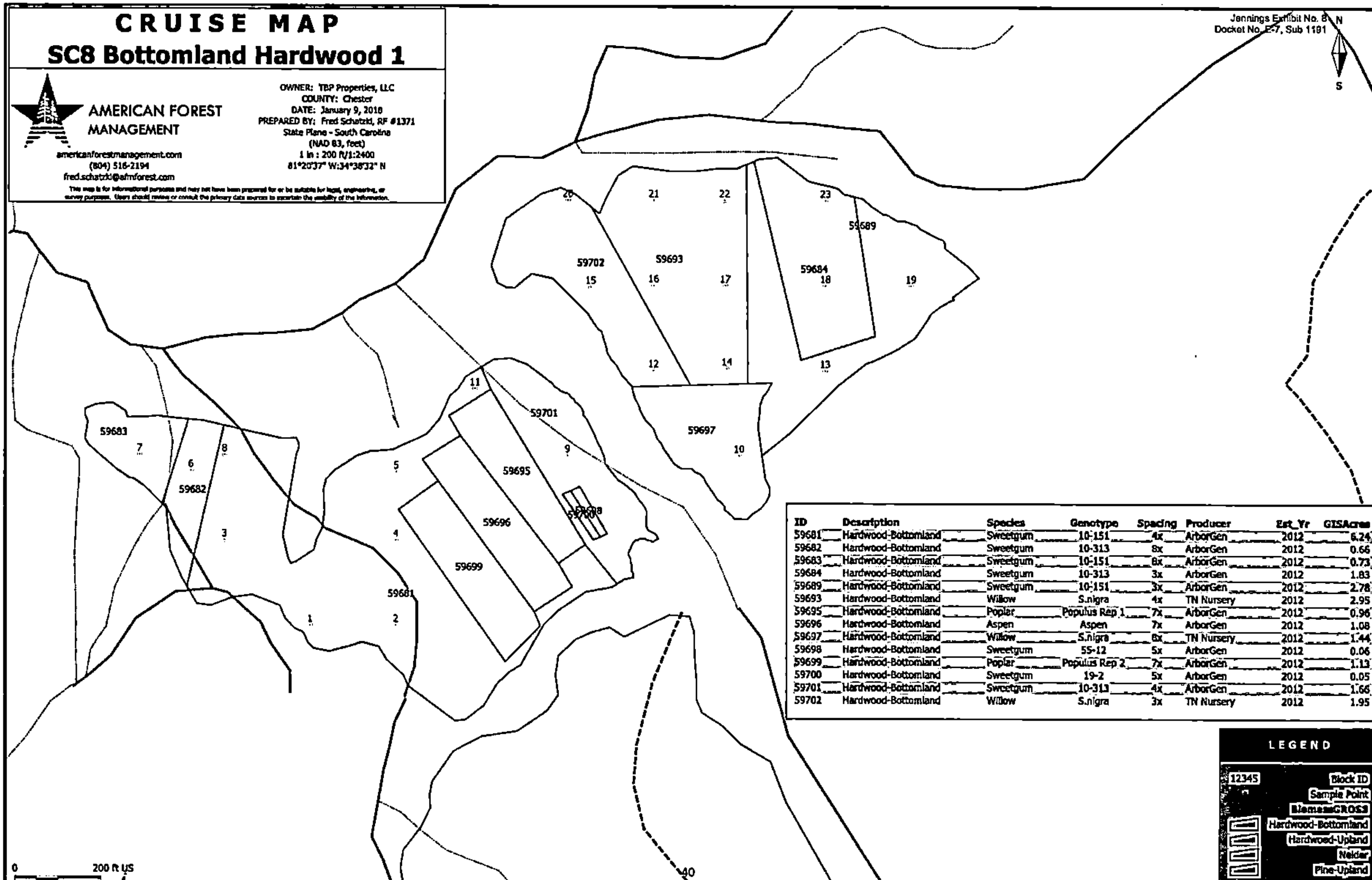
Jennings Exhibit No. 8
Docket No. E-7, Sub 1191

CRUISE MAP
SC8 Bottomland Hardwood 1

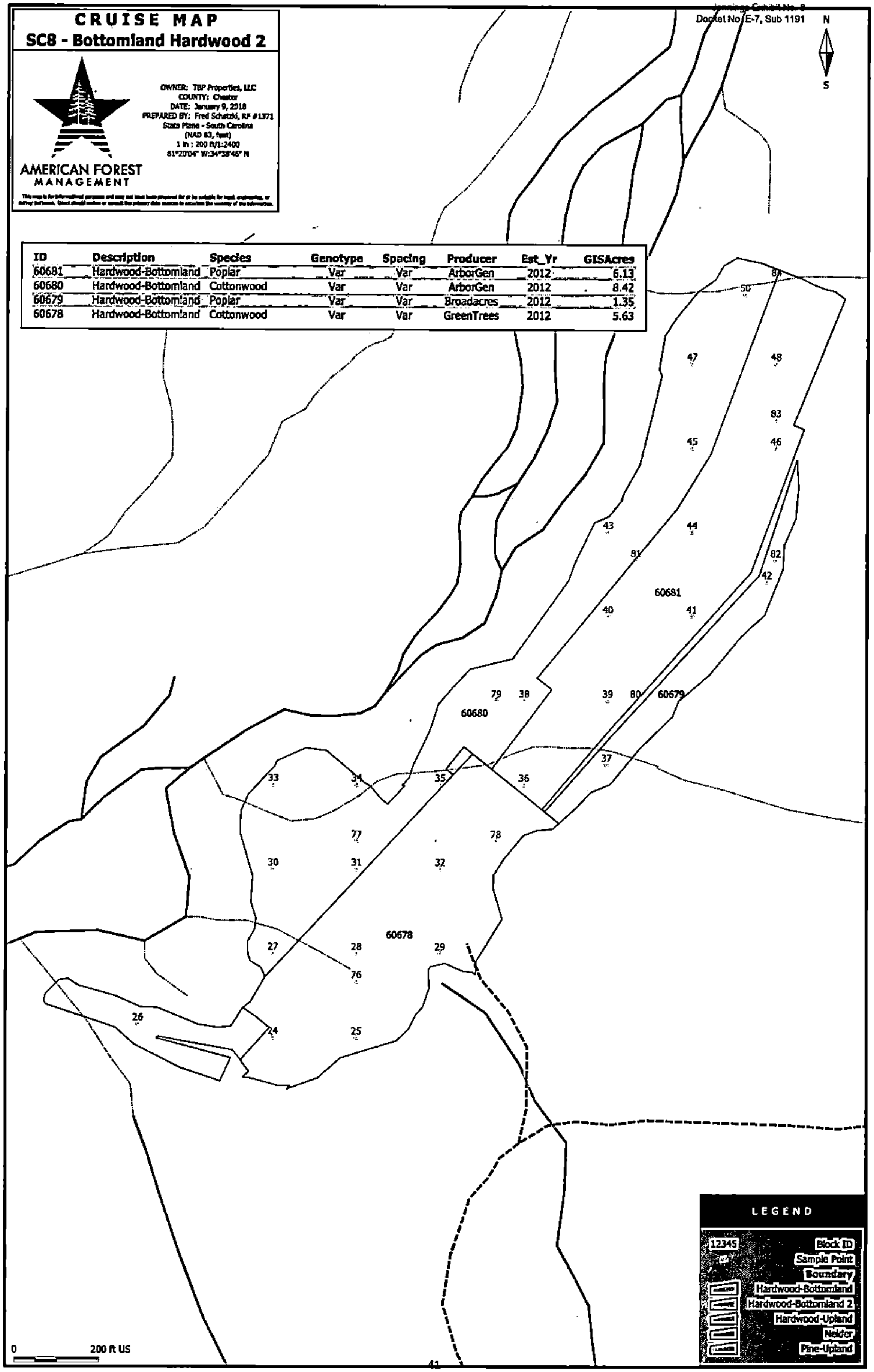
AMERICAN FOREST MANAGEMENT
americanforestmanagement.com
(804) 516-2194
fred.schatzki@afmforest.com

OWNER: TBP Properties, LLC
COUNTY: Chester
DATE: January 9, 2018
PREPARED BY: Fred Schatzki, RF #1371
State Plane - South Carolina
(NAD 83, feet)
1 in : 200 ft/1:2400
81°20'37" W:34°38'32" N

This map is for informational purposes and may not have been prepared for or be suitable for legal, engineering, or survey purposes. Users should review or consult the primary data sources to ascertain the usability of the information.



ID	Description	Species	Genotype	Spacing	Producer	Est_Yr	GISAcres
59681	Hardwood-Bottomland	Sweetgum	10-151	4x	ArborGen	2012	6.24
59682	Hardwood-Bottomland	Sweetgum	10-313	8x	ArborGen	2012	0.66
59683	Hardwood-Bottomland	Sweetgum	10-151	8x	ArborGen	2012	0.73
59684	Hardwood-Bottomland	Sweetgum	10-313	3x	ArborGen	2012	1.83
59689	Hardwood-Bottomland	Sweetgum	10-151	3x	ArborGen	2012	2.78
59693	Hardwood-Bottomland	Willow	S.nigra	4x	TN Nursery	2012	2.95
59695	Hardwood-Bottomland	Poplar	Populus Rep 1	7x	ArborGen	2012	0.96
59696	Hardwood-Bottomland	Aspen	Aspen	7x	ArborGen	2012	1.08
59697	Hardwood-Bottomland	Willow	S.nigra	8x	TN Nursery	2012	1.44
59698	Hardwood-Bottomland	Sweetgum	55-12	5x	ArborGen	2012	0.06
59699	Hardwood-Bottomland	Poplar	Populus Rep 2	7x	ArborGen	2012	1.13
59700	Hardwood-Bottomland	Sweetgum	19-2	5x	ArborGen	2012	0.05
59701	Hardwood-Bottomland	Sweetgum	10-313	4x	ArborGen	2012	1.66
59702	Hardwood-Bottomland	Willow	S.nigra	3x	TN Nursery	2012	1.95



ID	Description	Species	Genotype	Spacing	Producer	Est_Yr	GISAcres
60681	Hardwood-Bottomland	Poplar	Var	Var	ArborGen	2012	6.13
60680	Hardwood-Bottomland	Cottonwood	Var	Var	ArborGen	2012	8.42
60679	Hardwood-Bottomland	Poplar	Var	Var	Broadacres	2012	1.35
60678	Hardwood-Bottomland	Cottonwood	Var	Var	GreenTrees	2012	5.63

CRUISE MAP
SC8 - Upland Hardwood

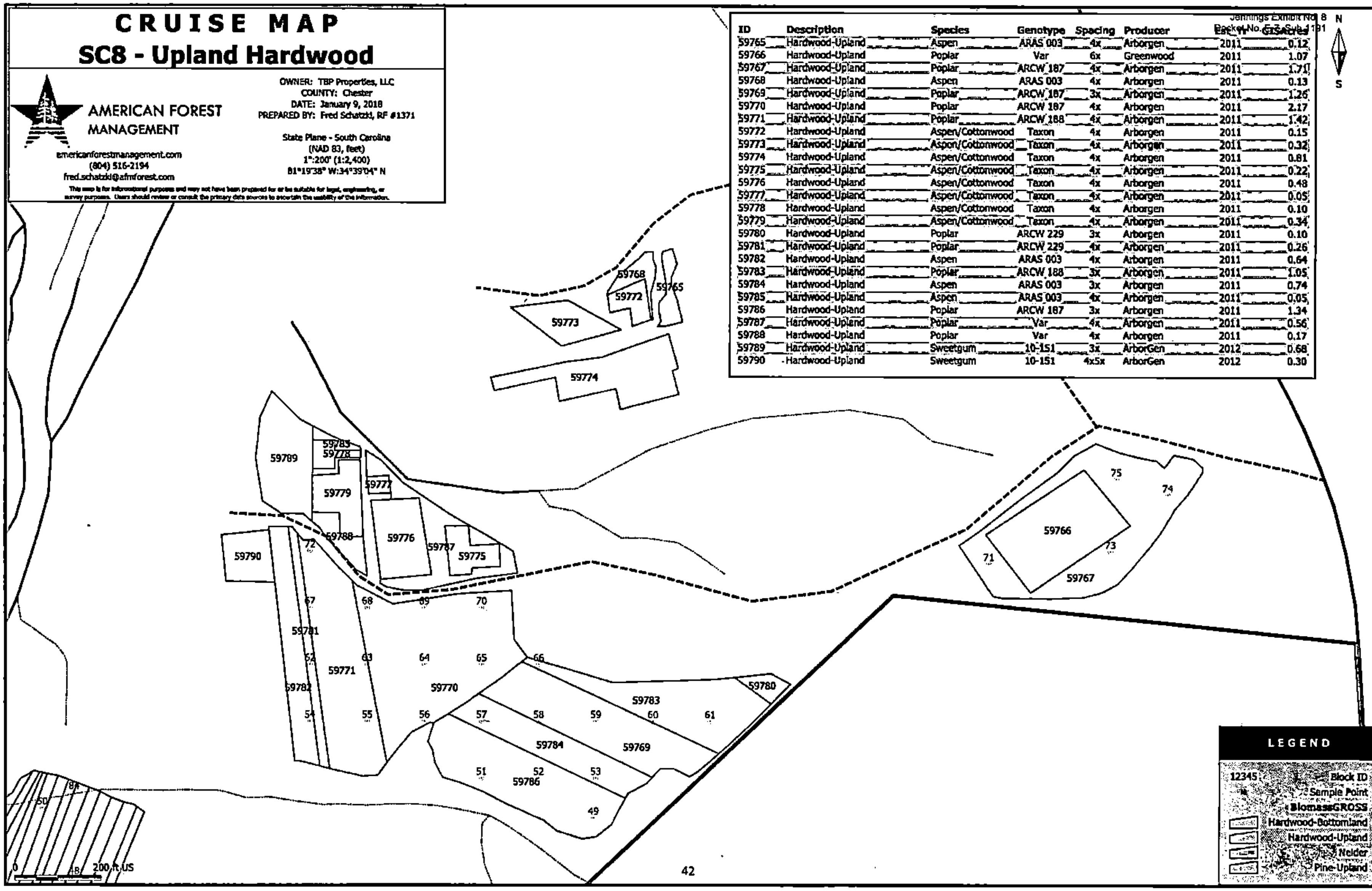
AMERICAN FOREST MANAGEMENT

americanforestmanagement.com
(804) 516-2194
fred.schatzki@afmforest.com

OWNER: TBP Properties, LLC
COUNTY: Chester
DATE: January 9, 2018
PREPARED BY: Fred Schatzki, RF #1371

State Plane - South Carolina
(NAD 83, feet)
1":200' (1:2,400)
81°19'38" W:34°39'04" N

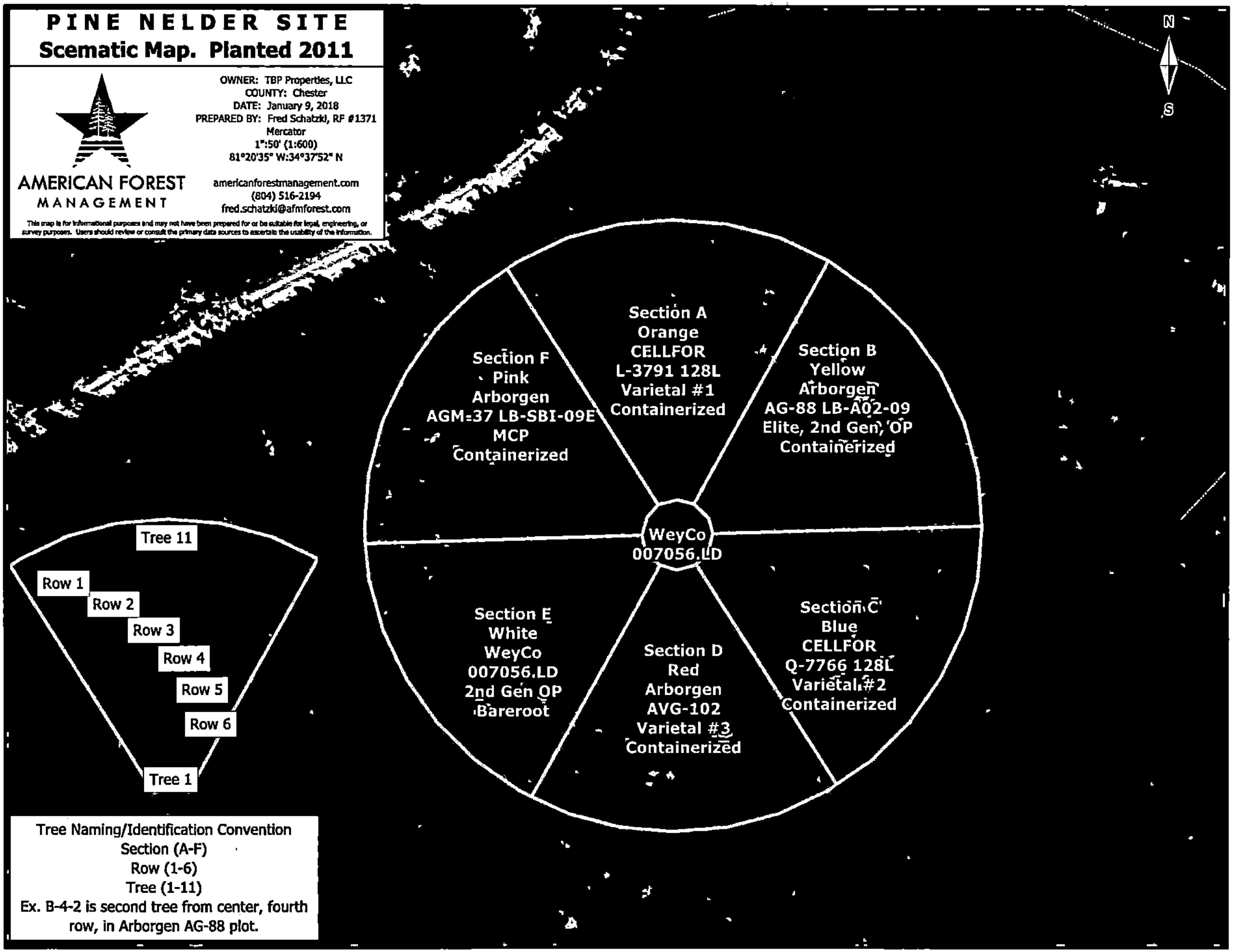
ID	Description	Species	Genotype	Spacing	Producer	Est. Yr	GISAcres
59765	Hardwood-Upland	Aspen	ARAS 003	4x	Arborgen	2011	0.12
59766	Hardwood-Upland	Poplar	Var	6x	Greenwood	2011	1.07
59767	Hardwood-Upland	Poplar	ARCW 187	4x	Arborgen	2011	1.71
59768	Hardwood-Upland	Aspen	ARAS 003	4x	Arborgen	2011	0.13
59769	Hardwood-Upland	Poplar	ARCW 187	3x	Arborgen	2011	1.26
59770	Hardwood-Upland	Poplar	ARCW 187	4x	Arborgen	2011	2.17
59771	Hardwood-Upland	Poplar	ARCW 188	4x	Arborgen	2011	1.42
59772	Hardwood-Upland	Aspen/Cottonwood	Taxon	4x	Arborgen	2011	0.15
59773	Hardwood-Upland	Aspen/Cottonwood	Taxon	4x	Arborgen	2011	0.32
59774	Hardwood-Upland	Aspen/Cottonwood	Taxon	4x	Arborgen	2011	0.81
59775	Hardwood-Upland	Aspen/Cottonwood	Taxon	4x	Arborgen	2011	0.22
59776	Hardwood-Upland	Aspen/Cottonwood	Taxon	4x	Arborgen	2011	0.48
59777	Hardwood-Upland	Aspen/Cottonwood	Taxon	4x	Arborgen	2011	0.05
59778	Hardwood-Upland	Aspen/Cottonwood	Taxon	4x	Arborgen	2011	0.10
59779	Hardwood-Upland	Aspen/Cottonwood	Taxon	4x	Arborgen	2011	0.34
59780	Hardwood-Upland	Poplar	ARCW 229	3x	Arborgen	2011	0.10
59781	Hardwood-Upland	Poplar	ARCW 229	4x	Arborgen	2011	0.26
59782	Hardwood-Upland	Aspen	ARAS 003	4x	Arborgen	2011	0.64
59783	Hardwood-Upland	Poplar	ARCW 188	3x	Arborgen	2011	1.05
59784	Hardwood-Upland	Aspen	ARAS 003	3x	Arborgen	2011	0.74
59785	Hardwood-Upland	Aspen	ARAS 003	4x	Arborgen	2011	0.05
59786	Hardwood-Upland	Poplar	ARCW 187	3x	Arborgen	2011	1.34
59787	Hardwood-Upland	Poplar	Var	4x	Arborgen	2011	0.56
59788	Hardwood-Upland	Poplar	Var	4x	Arborgen	2011	0.17
59789	Hardwood-Upland	Sweetgum	10-151	3x	ArborGen	2012	0.68
59790	Hardwood-Upland	Sweetgum	10-151	4x5x	ArborGen	2012	0.30



SC8 2018 Biomass Inventory Tally Sheet

Cruiser ____________ Date ____________ Sheet____________ of ____________ Naturals only, max 25

Block ID	Plot #	Species	Genotype	DBH	GLD	Height	Count


PINE NELDER SITE
Scematic Map. Planted 2011
OWNER: TBP Properties, LLC
COUNTY: Chester
DATE: January 9, 2018
PREPARED BY: Fred Schatzki, RF #1371
Mercator
1":50' (1:600)
81°20'35" W:34°37'52" N
AMERICAN FOREST MANAGEMENT
americanforestmanagement.com
(804) 516-2194
fred.schatzki@afmforest.com
This map is for informational purposes and may not have been prepared for or be suitable for legal, engineering, or survey purposes. Users should review or consult the primary data sources to ascertain the usability of the information.
N
S
Section A
Orange
CELLFOR
L-3791 128L
Varietal #1
Containerized
Section B
Yellow
Arborgen
AG-88 LB-A02-09
Elite, 2nd Gen, OP
Containerized
Section C
Blue
CELLFOR
Q-7766 128L
Varietal #2
Containerized
Section D
Red
Arborgen
AVG-102
Varietal #3
Containerized
Section E
White
WeyCo
007056.LD
2nd Gen OP
Bareroot
Section F
Pink
Arborgen
AGM-37 LB-SBI-09E
MCP
Containerized
WeyCo
007056.LD
Tree 11
Row 1
Row 2
Row 3
Row 4
Row 5
Row 6
Tree 1
Tree Naming/Identification Convention
Section (A-F)
Row (1-6)
Tree (1-11)
Ex. B-4-2 is second tree from center, fourth row, in Arborgen AG-88 plot.

SC8 2018 Nelder Tally Sheet

Cruiser ____ Date ____________

Section	Row	Tree	DBH	Height		Section	Row	Tree	DBH	Height		Section	Row	Tree	DBH	Height
A	1	1				A	2	1				A	3	1		
A	1	2			*	A	2	2			*	A	3	2		
A	1	3				A	2	3				A	3	3		
A	1	4				A	2	4				A	3	4		
A	1	5			*	A	2	5			*	A	3	5		
A	1	6				A	2	6				A	3	6		
A	1	7				A	2	7				A	3	7		
A	1	8			*	A	2	8			*	A	3	8		
A	1	9				A	2	9				A	3	9		
A	1	10				A	2	10				A	3	10		
A	1	11			*	A	2	11			*	A	3	11		
A	4	1				A	5	1				A	6	1		
A	4	2			*	A	5	2			*	A	6	2		
A	4	3				A	5	3				A	6	3		
A	4	4				A	5	4				A	6	4		
A	4	5			*	A	5	5			*	A	6	5		
A	4	6				A	5	6				A	6	6		
A	4	7				A	5	7				A	6	7		
A	4	8			*	A	5	8			*	A	6	8		
A	4	9				A	5	9				A	6	9		
A	4	10				A	5	10				A	6	10		
A	4	11			*	A	5	11			*	A	6	11		

I/A

Jennings Exhibit No. 9
Docket No. E-7, Sub 1191

MINERAL LABS INC.

Box 549
Salyersville, Kentucky 41465
Phone (606) 349-6145

Certificate of Analysis

COMPANY REQUESTING ANALYSIS:		
Duke Energy SC8 Biomass 400 S. Tryon St. Charlotte, NC 28202	Date Analyzed:	7/20/2018
	Lab No.	18021716
	Sampled By/Type:	Customer

Sample ID: Mail In: Wood Bark: LB 756 BO: July 2018: Duke Energy SC8 Site: Chester, SC: 179.8 grams

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture (D3302/D3173)	26.74	
% Ash (D3174)	0.68	0.93
% Volatile (D3175)	xxxxx	xxxxx
% Fixed Carbon (Calculated)	xxxxx	xxxxx
B.T.U (D5865/D5864)	7075	9657
M.A.F.B.T.U. (Calculated)	9748	
% Sulfur (D4239)	0.04	0.06
SO_2 lbs./mm Btu	0.12	
Ash lbs./mm Btu	0.96	

ULTIMATE ANALYSIS (ASTM D5373)	As Received	Dry Basis
Moisture	26.74	
Carbon	40.23	54.92
Hydrogen	5.41	7.39
Nitrogen	0.24	0.33
Sulfur	0.04	0.06
Ash	0.68	0.93
Oxygen (diff.)	26.64	36.37

SULFUR FORMS (ASTM D2492)	As Received	Dry Basis
% Pyritic Sulfur	xxxxx	xxxxx
% Sulfate Sulfur	xxxxx	xxxxx
% Organic Sulfur	xxxxx	xxxxx
% Total Sulfur	xxxxx	xxxxx

FUSION TEMPERATURE OF ASH (D1857)	Reducing (°F)	Oxidizing (°F)
Initial Temp.	xxxxx	xxxxx
Softening Temp. H=W	xxxxx	xxxxx
Hemispherical Temp. H=1/2 W	xxxxx	xxxxx
Fluid Temp	xxxxx	xxxxx

T-250 Temp. of Ash	xxxxx

Base/Acid Ratio	xxxxx
Fouling Factor	xxxxx
Slagging Factor	xxxxx

WATER SOLUBLE ALKALIES (Reported in %)	
CaO	xxxxx
K_2O	xxxxx
Na_2O	xxxxx

MINERAL ANALYSIS (ASTM D4326)		% Wt. Ignited Basis
Silicon dioxide	SiO_2	xxxxx
Aluminum oxide	Al_2O_3	xxxxx
Titanium dioxide	TiO_2	xxxxx
Iron oxide	Fe_2O_3	xxxxx
Calcium oxide	CaO	xxxxx
Magnesium oxide	MgO	xxxxx
Potassium oxide	K_2O	xxxxx
Sodium oxide	Na_2O	xxxxx
Sulfur trioxide	SO_3	xxxxx
Phosphorus pentoxide	P_2O_5	xxxxx
Strontium oxide	SrO	xxxxx
Barium oxide	BaO	xxxxx
Manganese oxide	MnO	xxxxx
Undetermined		xxxxx

Arsenic ppm (ASTM D6357)	xxxxx
Chlorine ppm (ASTM 6721)	xxxxx
Mercury ppm (ASTM D6722)	xxxxx
Oxidation (ASTM D5263)	xxxxx
Selenium ppm (ASTM D6357;MOD)	xxxxx
Free Swelling Index (D720)	xxxxx
Equilibrium Moisture (ASTM D1412)	xxxxx
Grindability Index (D409)	xxxxx

Submitted By: Sharlinda Matthews

MINERAL LABS INC.

Box 549
Salyersville, Kentucky 41465
Phone (606) 349-6145

Jennings Exhibit No. 9
Docket No. E-7, Sub 1191

Certificate of Analysis

COMPANY REQUESTING ANALYSIS:		
Duke Energy SC8 Biomass 400 S. Tryon St. Charlotte, NC 28202	Date Analyzed:	7/20/2018
	Lab No.	18021717
	Sampled By/Type:	Customer

Sample ID: Mail In: Wood Bark: LB 756 WO: July 2018: Duke Energy SC8 Site: Chester, SC: 957.8 grams

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture (D3302/D3173)	39.53	
% Ash (D3174)	0.51	0.85
% Volatile (D3175)	xxxxx	xxxxx
% Fixed Carbon (Calculated)	xxxxx	xxxxx
B.T.U (D5865/D5864)	5905	9765
M.A.F.B.T.U. (Calculated)	9849	
% Sulfur (D4239)	0.53	0.88
SO_2 lbs./mm Btu	1.80	
Ash lbs./mm Btu	0.87	

ULTIMATE ANALYSIS (ASTM D5373)	As Received	Dry Basis
Moisture	39.53	
Carbon	31.35	51.85
Hydrogen	4.98	8.23
Nitrogen	0.15	0.24
Sulfur	0.53	0.88
Ash	0.51	0.85
Oxygen (diff.)	22.95	37.95

SULFUR FORMS (ASTM D2492)	As Received	Dry Basis
% Pyritic Sulfur	xxxxx	xxxxx
% Sulfate Sulfur	xxxxx	xxxxx
% Organic Sulfur	xxxxx	xxxxx
% Total Sulfur	xxxxx	xxxxx

FUSION TEMPERATURE OF ASH (D1857)	Reducing (°F)	Oxidizing (°F)
Initial Temp.	xxxxx	xxxxx
Softening Temp. H=W	xxxxx	xxxxx
Hemispherical Temp. H=1/2 W	xxxxx	xxxxx
Fluid Temp	xxxxx	xxxxx

T-250 Temp. of Ash	xxxxx

Base/Acid Ratio	xxxxx
Fouling Factor	xxxxx
Slagging Factor	xxxxx

WATER SOLUBLE ALKALIES (Reported in %)	
CaO	xxxxx
K_2O	xxxxx
Na_2O	xxxxx

MINERAL ANALYSIS (ASTM D4326)		% Wt. Ignited Basis
Silicon dioxide	SiO_2	xxxxx
Aluminum oxide	Al_2O_3	xxxxx
Titanium dioxide	TiO_2	xxxxx
Iron oxide	Fe_2O_3	xxxxx
Calcium oxide	CaO	xxxxx
Magnesium oxide	MgO	xxxxx
Potassium oxide	K_2O	xxxxx
Sodium oxide	Na_2O	xxxxx
Sulfur trioxide	SO_3	xxxxx
Phosphorus pentoxide	P_2O_5	xxxxx
Strontium oxide	SrO	xxxxx
Barium oxide	BaO	xxxxx
Manganese oxide	MnO	xxxxx
Undetermined		xxxxx

Arsenic ppm (ASTM D6357)	xxxxx
Chlorine ppm (ASTM 6721)	xxxxx
Mercury ppm (ASTM D6722)	xxxxx
Oxidation (ASTM D5263)	xxxxx
Selenium ppm (ASTM D6357;MOD)	xxxxx
Free Swelling Index (D720)	xxxxx
Equilibrium Moisture (ASTM D1412)	xxxxx
Grindability Index (D409)	xxxxx

Submitted By: Sharlonda Mathews

Jennings Exhibit No. 9
Docket No. E-7, Sub 1191

MINERAL LABS INC.

Box 549
Salyersville, Kentucky 41465
Phone (606) 349-6145

Certificate of Analysis

COMPANY REQUESTING ANALYSIS:		
Duke Energy SC8 Biomass 400 S. Tryon St. Charlotte, NC 28202	Date Analyzed:	7/20/2018
	Lab No.	18021718
	Sampled By/Type:	Customer

Sample ID: Mail In: Wood: LB 756 WB: July 2018: Duke Energy SC8 Site: Chester, SC: 753.4 grams

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture (D3302/D3173)	xxxxx	
% Ash (D3174)	xxxxx	0.74
% Volatile (D3175)	xxxxx	xxxxx
% Fixed Carbon (Calculated)	xxxxx	xxxxx
B.T.U (D5865/D5864)	xxxxx	9138
M.A.F.B.T.U. (Calculated)	9206	
% Sulfur (D4239)	xxxxx	0.42
SO_2 lbs./mm Btu	0.92	
Ash lbs./mm Btu	0.81	

ULTIMATE ANALYSIS (ASTM D5373)	As Received	Dry Basis
Moisture	xxxxx	
Carbon	xxxxx	50.20
Hydrogen	xxxxx	8.09
Nitrogen	xxxxx	0.16
Sulfur	xxxxx	0.42
Ash	xxxxx	0.74
Oxygen (diff.)	xxxxx	40.39

SULFUR FORMS (ASTM D2492)	As Received	Dry Basis
% Pyritic Sulfur	xxxxx	xxxxx
% Sulfate Sulfur	xxxxx	xxxxx
% Organic Sulfur	xxxxx	xxxxx
% Total Sulfur	xxxxx	xxxxx

FUSION TEMPERATURE OF ASH (D1857)	Reducing (°F)	Oxidizing (°F)
Initial Temp.	xxxxx	xxxxx
Softening Temp. H=W	xxxxx	xxxxx
Hemispherical Temp. H=1/2 W	xxxxx	xxxxx
Fluid Temp	xxxxx	xxxxx

T-250 Temp. of Ash	xxxxx

MINERAL ANALYSIS (ASTM D4326)		% Wt. Ignited Basis
Silicon dioxide	SiO_2	xxxxx
Aluminum oxide	Al_2O_3	xxxxx
Titanium dioxide	TiO_2	xxxxx
Iron oxide	Fe_2O_3	xxxxx
Calcium oxide	CaO	xxxxx
Magnesium oxide	MgO	xxxxx
Potassium oxide	K_2O	xxxxx
Sodium oxide	Na_2O	xxxxx
Sulfur trioxide	SO_3	xxxxx
Phosphorus pentoxide	P_2O_5	xxxxx
Strontium oxide	SrO	xxxxx
Barium oxide	BaO	xxxxx
Manganese oxide	MnO	xxxxx
Undetermined		xxxxx

Base/Acid Ratio	xxxxx
Fouling Factor	xxxxx
Slagging Factor	xxxxx

Arsenic ppm (ASTM D6357)	xxxxx
Chlorine ppm (ASTM 6721)	xxxxx
Mercury ppm (ASTM D6722)	xxxxx
Oxidation (ASTM D5263)	xxxxx
Selenium ppm (ASTM D6357;MOD)	xxxxx
Free Swelling Index (D720)	xxxxx
Equilibrium Moisture (ASTM D1412)	xxxxx
Grindability Index (D409)	xxxxx

WATER SOLUBLE ALKALIES (Reported in %)	
CaO	xxxxx
K_2O	xxxxx
Na_2O	xxxxx

Submitted By: Sharlinda Matthews

I/A

JENNINGS CONFIDENTIAL EXHIBIT NO. 10

DOCKET NO. E-7, SUB 1191

CONFIDENTIAL – FILED UNDER SEAL

I/A

JENNINGS CONFIDENTIAL EXHIBIT NO. 11

DOCKET NO. E-7, SUB 1191

CONFIDENTIAL – FILED UNDER SEAL

I/A

JENNINGS CONFIDENTIAL EXHIBIT NO. 12

DOCKET NO. E-7, SUB 1191

CONFIDENTIAL – FILED UNDER SEAL

Page 1 of 260 pages previously filed in docket on Feb. 24, 2019 KTM

I/A

Loyd Ray Farms, Inc.
Innovative Animal Waste Management System
Permit No. AWI990031
Permit Compliance Semi-Annual Report

July 1, 2018 – December 31, 2018 Semi-Annual Reporting Period

Submitted January 31, 2019

Submitted on Behalf of:
Loyd Ray Farms, Inc.
2049 Center Rd.
Boonville, NC 27011

This Semi-Annual Compliance Report provides an overview of the manner in which the subject facility, Loyd Ray Farms, has maintained compliance with the conditions of the Innovative Animal Waste Management System permit for the reporting period from July 1, 2018 through December 31, 2018. During this reporting period, the system was operated in accordance with the Innovative Swine Waste Treatment System and subject to the requirements thereof.

Overview of System

The animal waste treatment system installed at Loyd Ray Farms is designed to meet the Environmental Performance Standards set forth by North Carolina law for new and expanded swine facilities through the use of nitrification/denitrification and further treatment. This report confirms on a semi-annual basis that the innovative waste management system is in compliance with NC Department of Environmental Quality and its divisions, to insure that the utilization of the anaerobic digester technology to turn raw animal waste into biogas for the purpose of reducing greenhouse gas emissions minimizes the overall environmental impact of the swine farm, and explains the occurrences of operations, and testing requirements over the six month period, to monitor the

I/A

JENNINGS CONFIDENTIAL EXHIBIT NO. 14

DOCKET NO. E-7, SUB 1191

CONFIDENTIAL – FILED UNDER SEAL

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JENNINGS CONFIDENTIAL EXHIBIT NO. 15

DOCKET NO. E-7, SUB 1191

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JENNINGS CONFIDENTIAL EXHIBIT NO. 16

DOCKET NO. E-7, SUB 1191

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JENNINGS CONFIDENTIAL EXHIBIT NO. 17

DOCKET NO. E-7, SUB 1191

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JENNINGS CONFIDENTIAL EXHIBIT NO. 18

DOCKET NO. E-7, SUB 1191

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JENNINGS CONFIDENTIAL EXHIBIT NO. 19

DOCKET NO. E-7, SUB 1191

CONFIDENTIAL – FILED UNDER SEAL

Jennings Exhibit No. 20
Docket No. E-7, Sub 1191

I/A

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Jun 28 2019

RTI INTERNATIONAL

Office of Research Contracts

3040 Cornwallis Road ▪ PO Box 12194 ▪ Research Triangle Park, NC 27709-2194 ▪ USA
Telephone 919.541.6000 ▪ Fax 919.541.7148 ▪ www.rti.org

October 16, 2018

Mr. Travis Payne
Business Development Manager Distributed Energy Resources
Duke Energy Corporation

Dear Mr. Payne,

RTI is pleased to conduct a study titled "Biogas Utilization in North Carolina: Opportunities and Impact Analysis" with grant funding of $250,000 per year for two years from Duke Energy. The objectives of the study will be to:

a. Determine the potential bioenergy/biogas resources available in North Carolina
b. Identify the most beneficial and optimum utilization of resources to maximize economic, environmental and societal advantages.

RTI will collaborate with Duke University, East Carolina University, North Carolina State University and University of North Carolina at Chapel Hill to carry out the tasks based on recommendations laid out in the NC Department of Environmental Quality's Energy Policy Council Report. The following will be the deliverables from this study:

1. Bioenergy/Biogas inventory for North Carolina
2. Impact analysis for various products from biogas
3. Decision-support tool
4. Optimal resource utilization plan

A preliminary budget breakdown is shown in Table 1. The budget splits between the subcontractors will be finalized during sub-award negotiations.

	Year 1	Year 2
RTI	$25,000	$25,000
Sub-Contractors		
Duke University		
East Carolina University		
NC State University		
Total Sub-Contractors	*$225,000*	*$225,000*
Total Grant Award	$250,000	$250,000

Table 1: Proposed preliminary budget

If this is acceptable to you, we would be pleased to authorize this effort as a grant pursuant to RTI's standard terms and conditions (https://www.rti.org/sites/default/files/ffp_quote_terms_final.pdf). Please note that any reference to a "fixed price contract" in the incorporated terms and conditions is hereby replaced with the term "grant."

If acceptable, please sign and return this offer letter at your earliest convenience. We plan to commence this two-year period of performance upon your acceptance of this offer and will submit an invoice for Year 1 promptly.

RTI INTERNATIONAL

Office of Research Contracts

3040 Cornwallis Road ▪ PO Box 12194 ▪ Research Triangle Park, NC 27709-2194 ▪ USA
Telephone 919.541.6000 ▪ Fax 919.541.7148 ▪ www.rti.org

Thank you for your consideration. If you have any questions regarding this submission, please contact me at kehayes@rti.org or 919-541-7482.

Sincerely,

Katie Hayes

Katie Hayes
Senior Contracting Officer

DUKE ENERGY CORPORATION ACCEPTANCE

David B. Johnson

Name David B. Johnson

Title Director

Date 10/23/18

I/A

JENNINGS CONFIDENTIAL EXHIBIT NO. 21

DOCKET NO. E-7, SUB 1191

CONFIDENTIAL – FILED UNDER SEAL

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JENNINGS CONFIDENTIAL EXHIBIT NO. 22

DOCKET NO. E-7, SUB 1191

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JENNINGS CONFIDENTIAL EXHIBIT NO. 23

DOCKET NO. E-7, SUB 1191

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I/A

REDACTED VERSION

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191
Compliance Costs for the EMF Period January 1, 2018 to December 31, 2018

Line No.	Renewable Resource	RECs	MWh (Energy)	Total Cost	Avoided Cost	Incremental Cost	Avoided Cost Recovered in Fuel Cost Adjustment Rider		Deduct: Incremental Cost January 2018 through April 2018 (1)	Incremental Cost Adjusted EMF Period May 2018 through December 2018 (1)	
1	[redacted]										(p)
2											(q)
3											(r)
4											(s)
5											(t)
6											
7											(u)
8	[redacted]					$ 26,159,370			$ 6,942,007	$ 19,217,363	
9	Other Incremental			$ 1,030,461	Jennings Exhibit No. 3	$ 1,030,461		(g)	$ 163,562	$ 866,899	(v)
10	Solar Rebate Program			$ 135,912		$ 135,912		(h)	$ -	$ 135,912	(w)
11	Research			$ 938,393		$ 938,393		(i)	$ 145,949	$ 792,444	(x)
12	Total			[redacted] Jennings Exhibit No. 2		$ 28,264,136 (below)			$ 7,251,518	$ 21,012,618 (below)	

Line No.	Incremental cost category	Incremental Cost	Percent of Total Incremental Cost	Incremental Cost	Percent of Total Incremental Cost
13	[redacted]				
14					
15	Total	$ 28,264,136 (above)		$ 21,012,618 (above) to Williams Exhibit No. 2, page 1	

Allocate incremental cost of solar resources between solar compliance requirement and general compliance requirement:

Line No.	
16	[redacted]
17	
18	
19	
20	
21	

(1) In Docket No. E-7, Sub 1162, the EMF Period was updated to include the months of Jan - Apr 2018. Total REPS compliance activity and costs for the calendar year period Jan - Dec 2018 are included for review and audit in the current docket E-7, Sub 1191, however, incremental costs for Jan - Apr 2018 are excluded from the rider calculation.

REDACTED VERSION

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191
Projected Compliance Costs for the Billing Period September 1, 2019 to August 31, 2020

Williams Exhibit No. 1

February 26, 2019

Line No.	Renewable Resource	RECs	MWh (Energy)	Total Cost	Avoided Cost	Incremental Cost	Avoided Cost Recovered in Fuel Cost Adjustment Rider	
1	[redacted]							(a)
2								(b)
3								(c)
4								(d)
5								(e)
6								(p)
7								
8								(f)
9	[redacted]					$ 35,031,646		
10	Other Incremental			$ 1,567,500		$ 1,567,500		(g)
11	Estimated receipts related to contract performance			$ (1,000,000)	Jennings Exhibit No. 2	$ (1,000,000)		(q)
12	Solar Rebate Program			$ 1,137,395		$ 1,137,395		(h)
13	Research			$ 895,000		$ 895,000		(i)
14	Total			[redacted] Jennings Exhibit No. 2		$ 37,631,541 (below)		

Line No.	Incremental cost category	Incremental Cost	Percent of Total Incremental Cost
15	[redacted]		
16			
17	Total	$ 37,631,541 (above)	

Allocate estimated incremental cost of solar resources between solar compliance requirement and general compliance requirement:

18
19
20
21
22
23
[redacted]

I/A

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191

Compliance Costs for the adjusted EMF Period May 1, 2018 to December 31, 2018

Removed incremental compliance costs incurred January 1, 2018 through April 30, 2018 - recovered in updated EMF Period in docket No. E-7, Sub 1162

Allocate Incremental Cost per Customer Class - adjusted EMF Period May 2018 through December 2018

Combined North Carolina Retail and Wholesale

Line No.	Customer Class	Total Unadjusted Number of Accounts[1]	Adjustment for Self-supplied Requirements[1]	Total Adjusted Number of Accounts[1]	Annual Rider Cap per Customer Class Account	Annual Adjusted Revenue Cap	Cost Cap Allocation Factor	Actual Incremental Costs for REPS Recovery	Annual Per Account Charge [2]
1	Residential	1,883,228	462,139	1,421,089	$ 27	$ 38,369,403	53.17%	$ 11,172,409	$ 7.86
2	General	264,748	64,877	199,871	$ 150	$ 29,980,650	41.54%	$ 8,728,642	$ 43.67
3	Industrial	5,068	1,247	3,821	$ 1,000	$ 3,821,000	5.29%	$ 1,111,567	$ 290.91
4	Total	2,153,044	528,263	1,624,781		$ 72,171,053	100.00%	$ 21,012,618	(b)

Williams Exhibit No. 1, page 1 Line No. 12

Calculate NC Retail-only annual REPS cost per Customer Class - adjusted EMF Period:

North Carolina Retail Only

Line No.	Customer Class	Total Adjusted Number of Accounts - DEC Retail[1]	Annual Per Account Charge[2]	Incremental Costs Allocated to DEC Retail		Percent of Incremental Cost	NC Retail Percent of Total Incremental Cost	
5	Residential	1,289,168	$ 7.86	$ 10,132,860				
6	General	183,807	$ 43.67	$ 8,026,852				
7	Industrial	3,596	$ 290.91	$ 1,046,112				
8	Total	1,476,571		19,205,824	(a)		91.40%	(a) / (b)
9	Set-aside, Other Incremental, Solar Rebate, and Research			$ 12,157,287		63.3%	Williams Exhibit No. 1, page 1 Line Nos. 13,14	
10	General RECs			$ 7,048,537		36.7%		
11	Total Incremental Cost for Retail			19,205,824				

Notes:

(1) Average number of accounts subject to REPS charge during 2018.

(2) Annual per account charges are the result of the allocation of REPS costs between Duke Energy Carolinas Retail customers and the Company's Wholesale REPS customers, and are used only for calculating the total cost obligations of Duke Energy Carolinas Retail customers and the wholesale REPS customers, respectively. Proposed REPS rider charges per account are instead calculated using unadjusted REPS account totals by class - see Williams Exhibit No. 4.

REDACTED VERSION

Compliance Costs for the adjusted EMF Period May 1, 2018 to December 31, 2018

Calculate Set-aside and other incremental costs per customer class - adjusted EMF Period May 2018 through December 2018:

North Carolina Retail Only

Line No.	Customer Class	Total Unadjusted Number of Accounts[1]	Annual Rider Cap per Customer Class Account	Calculated Annual Revenue Cap	Cost Cap Allocation Factor	Allocated Annual Set-aside, Other Incremental, Solar Rebate Program, and Research Cost
1	Residential	1,718,891	$ 27	46,410,057	52.76%	$ 6,414,113
2	General	245,076	$ 150	36,761,400	41.79%	$ 5,080,618
3	Industrial	4,794	$ 1,000	4,794,000	5.45%	$ 662,556
4	Total	1,968,761		87,965,457		$ 12,157,287
						Williams Ex. No. 2 Pg 1 Line No. 9

Calculate General Requirement incremental costs per customer class - adjusted EMF Period May 2018 through December 2018:

North Carolina Retail Only

Line No.	Customer Class	Number of RECs for General compliance[3] (a)	% of EE REC supplied by Class[2]	REC Requirement supplied by EE by class[b]	Number of General RECs net of EE (c) = (a) - (b)	General Cost Allocation Factor (e) = (c) / (d)	Allocated Annual General Incremental Costs
5	Residential	[redacted]	40.00%	[redacted]		60.83%	$ 4,287,625
6	General		45.60%			39.38%	$ 2,775,714
7	Industrial		14.40%			-0.21%	$ (14,802)
8	Total		100.00%			100.00%	$ 7,048,537
		(4)		(6)	(d)		Williams Ex. No. 2 Pg 1 Line No. 10

Total cost allocation by customer class - adjsuted EMF Period:

		Total Incremental REPS cost by class	% Incremental REPS cost by class
9	Residential	$ 10,701,738	55.72%
10	General	$ 7,856,332	40.91%
11	Industrial	$ 647,754	3.37%
12	Total	$ 19,205,824	100.00%
		Williams Ex. No. 2 Pg 1 Line No. 11	

(1) Average number of accounts subject to REPS charge during 2018.
(2) EE allocated to account type according to actual relative contribution by customer class of EE RECs.
(3) Total General RECs per note (4) * "Cost Cap Allocation Factor" by class per line Nos. 1-3 above.
(4) [redacted] (5)
(4)
(5)
(6)
(6)

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191

Williams Exhibit No. 2
Page 3 of 3
February 26, 2019

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Jun 28 2019

Compliance Costs for the adjusted EMF Period May 1, 2018 to December 31, 2018

Calculate Incremental Cost Under/(Over) Collection per Customer Class - adjusted EMF Period

		North Carolina Retail Only						
Line No.	Account Type	Allocated Annual Set-aside, Other Incremental, Solar Rebate Program, and Research Cost	Allocated Annual General Incremental Costs	Total Incremental Costs Incurred May 2018 through December 2018	Actual NC Retail REPS Revenues Realized - May 2018 through December 2018	REPS EMF - Under/(Over)-Collection, before Interest	Interest on Over-collection[1]	REPS EMF - Under/(Over)-Collection
1	Residential	$ 6,414,113	$ 4,287,625	$ 10,701,738	$ 11,538,330	$ (836,592)	$ (125,489)	$ (962,081)
2	General	$ 5,080,618	$ 2,775,714	$ 7,856,332	$ 7,989,270	$ (132,938)	$ (19,941)	$ (152,879)
3	Industrial	$ 662,556	$ (14,802)	$ 647,754	$ 574,064	$ 73,690	$ -	$ 73,690
4	Total	$ 12,157,287	$ 7,048,537	$ 19,205,824	$ 20,101,664	$ (895,840)	$ (145,430)	$ (1,041,270)
		Williams Ex. No. 2 Pg 2 Line No. 4	Williams Ex. No. 2 Pg 2 Line No. 8	Williams Ex. No. 2 Pg 2 Line No. 12				

Note:
(1) Interest calculated at annual rate of 10% for number of months from mid-point of EMF period to mid-point of prospective rider billing period.

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Jun 28 2019

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191
For the Period September 1, 2019 to August 31, 2020

Allocate Incremental Cost per Customer Class - Billing Period

Line No.	Customer Class	Total Unadjusted Number of Accounts[1]	Adjustment for Self-supplied Requirements[1]	Total Adjusted Number of Accounts[1]	Annual Rider Cap per Customer Class Account	Annual Adjusted Revenue Cap	Cost Cap Allocation Factor	Projected Incremental Costs	Annual Per Account Charge[2]
		Combined North Carolina Retail and Wholesale							
1	Residential	1,877,424	460,360	1,417,064	$ 27	$ 38,260,728	53.46%	$ 20,117,822	$ 14.20
2	General	261,151	63,971	197,180	$ 150	$ 29,577,000	41.33%	$ 15,553,116	$ 78.88
3	Industrial	4,947	1,218	3,729	$ 1,000	$ 3,729,000	5.21%	$ 1,960,603	$ 525.77
4	Total	2,143,522	525,549	1,617,973		$ 71,566,728	100.00%	$ 37,631,541	
								Williams Exhibit No. 1, page 2 Line No. 14	

Calculate NC Retail-only annual REPS cost per Customer Class - Billing Period

Line No.	Customer Class	Total Adjusted Number of Accounts - Duke Retail[1]	Annual Per Account Charge[2]	Incremental Costs Allocated to Duke Retail		
		North Carolina Retail Only				
5	Residential	1,307,450	$ 14.20	$ 18,565,790		
6	General	184,358	$ 78.88	$ 14,542,159		
7	Industrial	3,570	$ 525.77	$ 1,876,999		
8	Total	1,495,378		34,984,948		
9	Set-aside, Other Incremental, Solar Rebate, and Research			$ 23,055,081	65.9%	Williams Exhibit No.
10	General RECs			$ 11,929,867	34.1%	1, page 2 Line Nos.
11	Total Incremental Cost for Retail			34,984,948		15, 16

Notes:

(1) Projected number of accounts subject to REPS charge during the billing period.

(2) Annual per account charges are the result of the allocation of REPS costs between Duke Energy Carolinas Retail customers and the Company's Wholesale REPS customers, and are used only for calculating the total cost obligations of Duke Energy Carolinas Retail customers and the wholesale REPS customers, respectively. Proposed REPS rider charges per account are instead calculated using unadjusted REPS account totals by class - see Williams Ex. No. 4.

REDACTED VERSION

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191
For the Period September 1, 2019 to August 31, 2020

Calculate Set-aside and other incremental costs per customer class - Billing Period:

North Carolina Retail Only

Line No.	Customer Class	Total Unadjusted Number of Accounts[1]	Annual Rider Cap per Customer Class Account	Calculated Annual Revenue Cap	Cost Cap Allocation Factor	Allocated Annual Set-aside, Other Incremental, Solar Rebate Program, and Research Cost
1	Residential	1,743,267	$ 27	47,068,209	53.06%	$ 12,234,103
2	General	245,810	$ 150	36,871,500	41.57%	$ 9,583,745
3	Industrial	4,760	$ 1,000	4,760,000	5.37%	$ 1,237,233
4	Total	1,993,837		88,699,709	100.00%	$ 23,055,081
						Williams Ex. No. 3 Pg 1 Line 9

Calculate General costs per customer class - Billing Period:

North Carolina Retail Only - Billing Period

Line No.	Customer Class	Number of RECs for General compliance (2) (a)	% of EE REC supplied by Class[3]	REC Requirement supplied by EE by class (b)	Number of General RECs net of EE (c) = (a) - (b)	General Cost Allocation Factor (e) = (c) / (d)	Allocated Annual General Incremental Costs
5	Residential	[redacted]	40.00%	[redacted]	[redacted]	61.61%	$ 7,349,991
6	General	[redacted]	45.60%	[redacted]	[redacted]	38.93%	$ 4,644,297
7	Industrial	[redacted]	14.40%	[redacted]	[redacted]	-0.54%	$ (64,421)
8	Total	[redacted]	100.00%	[redacted]	[redacted]	100.00%	$ 11,929,867
		(4)		(6)	(d)		Williams Ex. No. 3 Pg 1 Line 10

Total cost allocation by customer class - Billing Period:

Line No.	Customer Class	Total Incremental REPS cost by class	% Incremental REPS cost by class
9	Residential	$ 19,584,094	55.98%
10	General	$ 14,228,042	40.67%
11	Industrial	$ 1,172,812	3.35%
12	Total	$ 34,984,948	100.00%
		Williams Ex. No. 3 Pg 1 Line 11	

(1) Projected number of accounts subject to REPS charge during the billing period.
(2) EE allocated to account type according to actual projected contribution by customer class of EE RECs.
(3) Total General RECs per note (4) * "Cost Cap Allocation Factor" by class per line Nos. 1-3 above.

(4) [redacted] (5)
(4)
(5)
(6)
(6)

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191
For the Period September 1, 2019 to August 31, 2020

Williams Exhibit No. 3
Page 3 of 3
February 26, 2019

Calculate Incremental Cost to Collect by Customer Class - Billing Period:

		North Carolina Retail Annual Rider Cost by Account Type		
Line No.	Customer Class	Allocated Annual Set-aside and Other Incremental costs	Allocated Annual General Incremental Costs	Total Incremental Costs
1	Residential	$ 12,234,103	$ 7,349,991	$ 19,584,094
2	General	$ 9,583,745	$ 4,644,297	$ 14,228,042
3	Industrial	$ 1,237,233	$ (64,421)	$ 1,172,812
4	**Total**	**$ 23,055,081**	**$ 11,929,867**	**$ 34,984,948**
		Williams Exhibit No. 3, Pg 2, line 4	Williams Exhibit No. 3, Pg 2, line 8	Williams Exhibit No. 3, Pg 2, line 12

Calculate DEC NC Retail monthly REPS rider components:

		North Carolina Retail						
Line No.	Customer Class	Total Projected Number of Accounts -Duke Retail[1]	Annual REPS EMF Under/(Over)-Collection	Contract Amendments, Penalties, Change-of-control, Etc. [3]	Total EMF costs/(credits)	Monthly EMF Rider[2]	Projected Total Incremental Costs	Monthly REPS Rider[2]
1	Residential	1,743,267	$ (962,081)	$ (509,884)	$ (1,471,965)	$ (0.07)	$ 19,584,094	$ 0.94
2	General	245,810	$ (152,879)	$ (374,315)	$ (527,194)	$ (0.18)	$ 14,228,042	$ 4.82
3	Industrial	4,760	$ 73,690	$ (30,862)	$ 42,828	$ 0.75	$ 1,172,812	$ 20.53
4		1,993,837	$ (1,041,270)	$ (915,061)	$ (1,956,331)		$ 34,984,948	
			Williams Ex. No. 2 Pg 3 Line No. 4				Williams Ex. No. 3 Pg 3 Line No. 4	

Compare total annual REPS charges per account to per-account cost caps:

		North Carolina Retail						
Line No.	Customer Class	Monthly EMF Rider[2]	Monthly REPS Rider[2]	Combined Monthly Rider[2]	Regulatory Fee Multiplier	Total Monthly REPS Charge including Regulatory Fee	Total Annual REPS Charge including Regulatory Fee	Per-Account Cost Cap
5	Residential	$ (0.07)	$ 0.94	$ 0.87	1.001402	$ 0.87	$ 10.44	$ 27.00
6	General	$ (0.18)	$ 4.82	$ 4.64	1.001402	$ 4.65	$ 55.80	$ 150.00
7	Industrial	$ 0.75	$ 20.53	$ 21.28	1.001402	$ 21.31	$ 255.72	$ 1,000.00

Notes:

(1) Projected number of accounts subject to REPS charge during the billing period.

(2) Per account rate calculations apply to Duke Energy Carolinas NC Retail customers only.

(3) Credit for receipts for contract amendments, penalties, change-of-control, etc for adjusted EMF Period May 2018 through December 2018:

Customer Class	Total contract receipts - Adjusted EMF Period May 2018 - Dec 2018	NC retail percentage of EMF Period costs - Williams Exhibit No. 2, Pg 1	Allocation to customer class - Williams Exhibit No. 2, Pg 2	Receipts for contract amendments, penalties, change-of-control, etc.
Residential			55.72%	$ (509,884)
General			40.91%	$ (374,315)
Industrial			3.37%	$ (30,862)
Total contract payments received	$ (1,001,160) [4]	$ (915,061)		$ (915,061)
		91.40%		

Contract payments received Jan-Dec 2018 (Jennings Exhibit No 2)	$	(1,011,160)
Less: Contract Payments payments received Jan-Apr 2018 (updated in EMF Period in Docket No. E-7, sub 1162	$	(10,000)
Contract payments received - adjusted EMF Period May-Dec 2018	$	(1,001,160) [4]

I/A

REPS (NC)
RENEWABLE ENERGY PORTFOLIO STANDARD RIDER

APPLICABILITY (North Carolina Only)
Service supplied to the Company's retail customer agreements is subject to a REPS Monthly Charge. This charge is adjusted annually, pursuant to North Carolina General Statute 62-133.8 and North Carolina Utilities Commission Rule R8-67 as ordered by the North Carolina Utilities Commission. This Rider is not applicable to agreements for the Company's outdoor lighting rate schedules, OL, PL, NL, nor for services defined as auxiliary to another agreement. An auxiliary service is defined as a non-demand metered, nonresidential service, provided on Schedule SGS, at the same premises, with the same service address, and with the same account name as an agreement for which a monthly REPS charge has been applied.

APPROVED REPS MONTHLY CHARGE
The Commission has ordered that a REPS Monthly Charge, which includes an Experience Modification Factor (EMF), be included in the customers' bills as follows:

RESIDENTIAL SERVICE AGREEMENTS	
REPS Monthly Charge	$ 0.94
Experience Modification Factor	($ 0.07)
Net REPS Monthly Charge	$ 0.87
Regulatory Fee Multiplier	1.001402
Total REPS Monthly Charge per agreement per month	$ 0.87
GENERAL SERVICE AGREEMENTS	
REPS Monthly Charge	$ 4.82
Experience Modification Factor	($ 0.18)
Net REPS Monthly Charge	$ 4.64
Regulatory Fee Multiplier	1.001402
Total REPS Monthly Charge per agreement per month	$ 4.65
INDUSTRIAL SERVICE AGREEMENTS	
REPS Monthly Charge	$ 20.53
Experience Modification Factor	$ 0.75
Net REPS Monthly Charge	$ 21.28
Regulatory Fee Multiplier	1.001402
Total REPS Monthly Charge per agreement per month	$ 21.31

USE OF RIDER
The REPS Billing Factor is not included in the Company's current rate schedules and will apply as a separate charge to each agreement for service covered under this Rider as described above, unless the service qualifies for a waiver of the REPS Billing Factor for an auxiliary service. An auxiliary service is a non-demand metered nonresidential service, on Schedule SGS for the same customer at the same service location.

To qualify for an auxiliary service, not subject to this Rider, the Customer must notify the Company and the Company must verify that such agreement is considered an auxiliary service, after which the REPS Billing Factor will not be applied to qualifying auxiliary service agreements. The Customer shall also be responsible for notifying the Company of any change in service that would no longer qualify the service as auxiliary.

I/A

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191

Williams Exhibit No. 6

February 26, 2019

Worksheet detailing energy efficiency certificate ("EEC") inventory

EEC inventory reconciliation - as of December 31, 2018	EECs [1]	Reference
EECs carried forward at Dec 31, 2012	1,587,596	2012 Compliance Report - Docket No. E-7, Sub 1034
EECs generated for 2013 per Company's annual update	1,530,891	E-7, Sub 1052, Williams Exhibit No. 6
Less: EECs used for compliance for 2013	409,169	2013 Compliance Report - Docket No. E-7, Sub 1052
EECs carried forward at Dec 31, 2013	2,709,318	2013 Compliance Report - Docket No. E-7, Sub 1052
EECs generated for 2014 per Company's annual update	2,011,450	E-7, Sub 1074, Williams Exhibit No. 6
Less: EECs used for compliance for 2014	415,459	2014 Compliance Report - Docket No. E-7, Sub 1074
EECs carried forward at Dec 31, 2014	4,305,309	2014 Compliance Report - Docket No. E-7, Sub 1074
EECs generated for 2015 per Company's annual update	2,310,608	E-7, Sub 1106, Williams Exhibit No. 6
Less: EECs used for compliance for 2015	855,980	2015 Compliance Report - Docket No. E-7, Sub 1106
EECs carried forward at Dec 31, 2015	5,759,937	2015 Compliance Report - Docket No. E-7, Sub 1106
EECs generated for 2016 per Company's annual update	2,152,597	E-7, Sub 1131, Williams Exhibit No. 6
Less: EECs used for compliance for 2016	866,492	2016 Compliance Report - Docket No. E-7, Sub 1131
EECs carried forward at Dec 31, 2016	7,046,042	2016 Compliance Report - Docket No. E-7, Sub 1131
EECs generated for 2017 per Company's annual update	2,531,010	E-7, Sub 1162, Williams Exhibit No. 6
Less: EECs used for compliance for 2017	863,135	2017 Compliance Report - Docket No. E-7, Sub 1162
EECs carried forward at Dec 31, 2017	8,713,917	2017 Compliance Report - Docket No. E-7, Sub 1162
EECs generated for 2018 per Company's annual update	3,060,454	Company workpapers [a]
Less: EECs used for compliance for 2018	1,400,307	2018 Compliance Report - Docket No. E-7, Sub 1191
EECs carried forward at Dec 31, 2018	10,374,064	2018 Compliance Report - Docket No. E-7, Sub 1191

Summary workpapers - EECs generated

	Program year							
Update for 2018 EECs generated - as of year-end 2018:	**2009 - 2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
Current view at year-end 2018	2,017,592	1,561,044	1,881,130	2,195,026	2,292,223	2,613,127	3,044,208	15,604,350
Previously reported current view at year-end 2017	2,017,592	1,561,044	1,881,130	2,194,959	2,291,703	2,597,468		12,543,896
Total Adjustments to previously reported results	0	0	0	67	520	15,659		
Updated EECs created and available for 2018				[b]	[c]	[d]		3,060,454 [a]

detail of adjustments at page 2 of 2

Footnote:

[1] Calculated EECs originate from details contained in the databases supporting Duke Energy Carolinas' energy efficiency filings, and are specific to North Carolina, calculated at the generation station level, are inclusive of free-ridership EE savings, and assume savings intiated in a program year continue for the duration of the life of the applicable measure.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191

Williams Exhibit No. 6
Page 2 of 2
February 26, 2019

Detail for adjustments to previously reported results through program year 2017:

Adjustment type	Program	Program year 2012	2013	2014	2015	2016	2017	Total
Evaluation, Measurement, & Verification ("EM&V"):								
	Non Residential Smart Saver Energy Efficient Lighting Products (NRLTG)	-	-	-	-	-	10,538	10,538
	Energy Efficient Appliances and Devices (EEAD)	-	-	-	-	-	5,969	5,969
	Income Qualified Energy Efficiency and Weatherization Assistance (IQEE & WA)	-	-	-	67	520	987	1,574
	Small Business Energy Saver (SBES)	-	-	-	-	-	(879)	(879)
	Non Residential Smart Saver Energy Efficient Food Service Products (NRFS)	-	-	-	-	-	(632)	(632)
	HVAC Energy Efficiency (HVAC EE)	-	-	-	-	-	(468)	(468)
	Residential Energy Assessments (EA)	-	-	-	-	-	7	7
	Non Residential Smart Saver Energy Efficient HVAC Products (NRHVAC)	-	-	-	-	-	3	3
	Non Residential Energy Efficient Process Equipment Products (NRPROC)	-	-	-	-	-	(4)	(4)
	Non Residential Energy Efficient Pumps and Drives Products (NRP&D)	-	-	-	-	-	1	1
Total EM&V adjustments		-	-	-	67	520	15,522	16,109
Participation updates/adjustments								
	Non Residential Smart Saver Custom Technical Assessments (NRCAMT)	-	-	-	-	-	137	137
Total participation adjustments		-	-	-	-	-	137	137
Total adjustments to prior program years incorporated into 2018 current view - EE savings for REPS		0	0	0	67 (b)	520 (c)	15,659 (d)	16,246

EM&V reports applicable to results reported above - filed as exhibits to the testimony of DEC witness Robert Evans in DEC's energy efficiency Docket No. E-2, Sub 1192:

Evans Exhibit	Program	Report Finalization Date	EM&V Report	Evaluation Type
B	Non Residential Smart Saver Energy Efficient Lighting Products (NRLTG)	3/25/2018	Nonresidential Smart Saver® Energy Efficient Products and Assessment – Prescriptive: 2015-2017	Process and Impact
C	Energy Efficient Appliances and Devices (EEAD)	4/6/2018	Residential Energy Efficient Appliances and Devices – Retail Lighting: 2016-2017	Process and Impact
I	Energy Efficient Appliances and Devices (EEAD)	10/4/2018	Residential Energy Efficient Appliances and Devices – Online Savings Store: 2015-2017	Process and Impact
F	Income Qualified Energy Efficiency and Weatherization Assistance (IQEE & WA)	6/13/2018	Income-Qualified Energy Efficiency and Weatherization Assistance: 2015-2016	Process and Impact
G	Small Business Energy Saver (SBES)	9/10/2018	Small Business Energy Saver: 2016-2017	Process and Impact
B	Non Residential Smart Saver Energy Efficient Food Service Products (NRFS)	3/25/2018	Nonresidential Smart Saver® Energy Efficient Products and Assessment – Prescriptive: 2015-2017	Process and Impact
E	HVAC Energy Efficiency (HVAC EE)	5/25/2018	Residential Smart Saver® Energy Efficiency - HVAC: 2016-2017	Process and Impact
J	Residential Energy Assessments (EA)	10/12/2018	Duke Energy Carolinas Residential Energy Assessments Program: 2016-2017	Process and Impact
B	Non Residential Smart Saver Energy Efficient HVAC Products (NRHVAC)	3/25/2018	Nonresidential Smart Saver® Energy Efficient Products and Assessment – Prescriptive: 2015-2017	Process and Impact
B	Non Residential Energy Efficient Process Equipment Products (NRPROC)	3/25/2018	Nonresidential Smart Saver® Energy Efficient Products and Assessment – Prescriptive: 2015-2017	Process and Impact
B	Non Residential Energy Efficient Pumps and Drives Products (NRP&D)	3/25/2018	Nonresidential Smart Saver® Energy Efficient Products and Assessment – Prescriptive: 2015-2017	Process and Impact

I/A

REDACTED VERSION

Summary cost recovery worksheet - DEC utility-owned solar project

Project:	**Woodleaf**	
Project size:	6 MWac	
CPCN docket No.	E-7, Sub 1101	
CPCN filing date:	March 3, 2016	
NCUC Order date:	June 16, 2016	
Original CPCN estimate:		
Total capital expenditure ($000s)	[redacted]	
Total annual levelized revenue requirement ($000s)		
Updated tax benefit monetization estimates:		
Total capital expenditure ($000s)	[redacted]	(Note 1)
Total annual levelized revenue requirement ($000s)		

Levelized cost recovery summary - annual:

Woodleaf	$./MWH	Percent to total	Annual Levelized cost ($000s)
Total cost - original estimate	[redacted]		
Avoided cost			
Incremental cost			
Cap for REPS cost recovery			
Total cost - updated tax benefit monetization estimates	[redacted]		
Avoided cost			
Incremental cost			
Cap for REPS cost recovery			

Note 1: The Woodleaf facility was placed in service in late December 2018, and final remaining project costs are still being recorded to the asset balance in 2019. Levelized incremental costs of the facility will be reflected in the future EMF Period beginning January 1, 2019, and will be subject to the cap for cost recovery in the REPS rider as established by the Commission in the CPCN Docket No. E-7, Sub 1101. In the current proposed rider calculation, the Company included only in its Billing Period a forecast of levelized cost limited to the approved avoided cost plus the incremental cost calculated at the cap.

I/A

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DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191
ADJUSTMENT TO RESEARCH COSTS
For the Year Ending December 31, 2018

Boswell Exhibit 1
Schedule 1

Line No.	Item	Amount
	Research Cost Detail:	1/
1	CAPER - Short Course Development	[redacted]
2	CAPER - Smart Battery Gauge	
3	Clemson University - Small DG Interface Testing	
4	Closed Loop Biomass	
5	Coalition for Renewable Natural Gas Membership	
6	DER Risks to Transformers and Transmission	
7	Eos Energy Storage Technology Development - McAlpine	
8	EPRI Membership	
9	EPRI - Inverter Onboard Islanding Detection Case Study Project	
10	ETO - Mitigation of Transformer High Inrush Current	
11	FREEDM Center - NCSU	
12	IEEE 1547 Conformity Assessment Test	
13	Loyd Ray Farms - Duke University	
14	Marshall Solar Site Storage Integration and Controller Design	
15	Mini-DVAR	
16	NCSU - ETO - Grid-forming Battery Energy Storage System Characterization [redacted]	
17	NCSU - Interactions of PV Installations with Distribution Systems	
18	PNNL - Dynamic Var Compensator Pilot	
19	Research Triangle Institute - Biogas Utilitzation in NC	
20	Rocky Mountain Institute - eLab	
21	Swine Extrusion/Poultry Mortality - NC State Natural Resources Foundation	
22	UNCC - Evaluation of Fault Scenarios and Mitigation Techniques	
23	UNCC - Hardware Cyber Security for DER Inverters	

24	Total Research Cost	$ 938,393	
25	Adjusment to remove research costs per Public Staff	[redacted]	2/
26	Total Research Costs per Public Staff (L24 + L25)		

1/ Jennings Confidental Exhibit 3, Lines 28 through 51.
2/ Recommended by Public Staff witness Lawrence.
3/ Confidential Information Highlighted

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191
EMF INCREMENTAL COST UNDER/(OVER) COLLECTION
For the Year Ending December 31, 2018

Boswell Exhibit 1
Schedule 2

		North Carolina Retail Only						
Line No.	Account Type	Allocated Annual Set-aside, Other Incremental, Solar Rebate Program, and	Allocated Annual General Incremental Costs	Total Incremental Costs Incurred May 2018	Actual NC Retail REPS Revenues Realized - May 2018 through	REPS EMF - Under/(Over)-Collection, before Interest	Interest on Over-collection[1]	REPS EMF - Under/(Over)-Collection
1	Residential	$ 6,394,131	$ 4,292,696	$ 10,686,827	$ 11,538,330	$ (851,503)	$ (127,725)	$ (979,228)
2	General	$ 5,064,790	$ 2,778,997	$ 7,843,787	$ 7,989,270	$ (145,483)	$ (21,822)	$ (167,305)
3	Industrial	$ 660,492	$ (14,819)	$ 645,673	$ 574,064	$ 71,609	$ -	$ 71,609
4	**Total**	$ 12,119,413	$ 7,056,874	$ 19,176,287	$ 20,101,664	$ (925,377)	$ (149,547)	$ (1,074,924)

Note:
(1) Interest calculated at annual rate of 10% for number of months from mid-point of EMF period to mid-point of prospective rider billing period.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1191
CALCULATION OF REPS RIDER COMPONENTS
For the Year Ending December 31, 2018

Boswell Exhibit 1
Schedule 3

		North Carolina Retail						
Line No.	Customer Class	Total Projected Number of Accounts -Duke Retail(1)	Annual REPS EMF Under/(Over)-Collection	Receipts for Contract Amendments, Penalties, Change-of-control, Etc. (3)	Total EMF costs/(credits)	Monthly EMF Rider(2)	Projected Total Incremental Costs	Monthly REPS Rider(2)
1	Residential	1,743,267	$ (979,228)	$ (510,125)	$ (1,489,353)	$ (0.07)	$ 19,584,094	$ 0.94
2	General	245,810	$ (167,305)	$ (374,416)	$ (541,721)	$ (0.18)	$ 14,228,042	$ 4.82
3	Industrial	4,760	$ 71,609	$ (30,821)	$ 40,788	$ 0.71	$ 1,172,812	$ 20.53
4		1,993,837	$ (1,074,924)	$ (915,362)	$ (1,990,286)		$ 34,984,948	

$ (0.85)
$ (2.20)
$ 8.57

Compare total annual REPS charges per account to per-account cost caps:

		North Carolina Retail						
Line No.	Customer Class	Monthly EMF Rider(2)	Monthly REPS Rider(2)	Combined Monthly Rider(2)	Regulatory Fee Multiplier	Total Monthly REPS Charge Including Regulatory Fee	Total Annual REPS Charge Including Regulatory Fee	Per-Account Cost Cap
5	Residential	$ (0.07)	$ 0.94	$ 0.87	1.001402	$ 0.87	$ 10.44	$ 27.00
6	General	$ (0.18)	$ 4.82	$ 4.64	1.001402	$ 4.65	$ 55.80	$ 150.00
7	Industrial	$ 0.71	$ 20.53	$ 21.24	1.001402	$ 21.27	$ 255.24	$ 1,000.00