Feasibility Review for a Wood Waste to Energy Conversion Facility on the Northern Arizona University Campus

Prepared for:
Northern Arizona University
Flagstaff, Arizona

Prepared by:
TSS Consultants
Rancho Cordova, California

April 2014

Acknowledgments

The authors wish to thank several individuals and organizations for their significant efforts in support of this project. These include, but are not limited to:

- Nick Koressel, Program Coordinator, Green Energy Initiative, Northern Arizona University
- Lindsay Wagner, Director of Energy Services and Sustainability, Northern Arizona University
- Marlin Johnson, Forester, Johnson Forestry Services
- Eli Lauren-Bernstein, Ecological Restoration Institute, Northern Arizona University
- Dick Fleishman, Assistant Team Leader, 4FRI, Coconino National Forest
- James Perkins, Perkins Timber Harvesting
- Ken Ribelin, High Desert Investment
- Steve Gatewood, Wildwood Consulting
- Patrick Rappold, Wood Utilization and Marketing Specialist, Arizona State Forestry
- Keith Pajkos, Forester, Arizona State Forestry
- Erin Phelps, Project Manager, Flagstaff Watershed Protection Project, Coconino National Forest
- Steve Horner, Forester, The Campbell Group
- Chris Stephans, CEO, Newpac Fibre LLC
- Kevin Ordean, Intern with Energy Services and Sustainability, Northern Arizona University
- Avi Henn, Sustainability Program Coordinator, Green Energy Initiative, Northern Arizona University
- Katharyn Woods, Doctoral Student – Climate and Landscape Change, Northern Arizona University
- Mike Talbsot, Facilities Operations, Northern Arizona University
- Brenda Hazlett, Relationship Manager, Arizona Public Service
- James Biddle, Manager, Environmental and Industrial Hygiene Programs, Office of Regulatory Compliance, Northern Arizona University
- Bruce Fox, Faculty, Northern Arizona University
- Diane Vosick, Faculty, Northern Arizona University

The TSS Consultants feasibility study team included:

- Tad Mason, Forester and CEO, Project Manager
- Frederick Tornatore, Chief Technical Officer
- Matt Hart, Renewable Energy Specialist

Table of Contents

List of Figures

List of Tables

Abbreviations

Organizations

ADEQ	Arizona Department of Environmental Quality
APS	Arizona Public Service
BLM	Bureau of Land Management
FWPP	Flagstaff Watershed Protection Project
NAU	Northern Arizona University
TSS	TSS Consultants
UES	Unisource Energy Services
USDA	United States Department of Agriculture
USFS	United States Forest Service

Other Terms

4FRI	Four Forest Restoration Initiative
Btu	British Thermal Unit
CCF	Hundred Cubic Feet
CH_4	Methane
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO_2	Carbon Dioxide
FSA	Feedstock Study Area
GREET	Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation Model
GT	Green Ton
H_2	Hydrogen
Hr	Hour
kWh	Kilowatt-hour
Lbs	Pounds
LLC	Limited Liability Corporation
MBH	Thousand British Thermal Units per Hour
MMBtu	Million British Thermal Units
MSCF	Thousand Standard Cubic Feet
MT	Metric Tonnes
MW	Megawatt
MWh	Megawatt-hour
N/A	Not Available
NEPA	National Environmental Policy Act
NF	National Forest
NO_x	Nitrous Oxides
PM	Particulate Matter
SCF	Standard Cubic Feet
SO_2	Sulfur Dioxide
TPD	Tons per Day
TPY	Tons per Year
U.S.	United States
VOC	Volatile Organic Compounds

EXECUTIVE SUMMARY

Background

The Northern Arizona University (NAU) Green Energy Initiative, a part of NAU Facility Services, is seeking to better understand the potential for biomass energy production using locally available forest waste, utilizing local labor, and supporting the regional economy while reducing NAU's consumption of fossil fuels. NAU is considering solutions to displace natural gas and electricity consumption consistent with NAU's 2020 Carbon Neutrality Goal as outlined in the NAU's 2010 Climate Action Plan. This study focuses on a bioenergy facility serving the electrical and/or thermal demand for the South Campus section of the NAU campus.

NAU retained TSS Consultants (TSS) to provide technical support and a feasibility analysis of bioenergy technology and conversion systems, renewable energy deployment strategies, and siting parameters to address the technical and economic feasibility of bioenergy development.

Energy Load Assessment

The Energy Load Assessment identified three potential opportunities for bioenergy development. Optimal project sizes to fit within campus property are shown in Table 1. The North Campus Heating and Cooling Plant was not considered a viable option for bioenergy development at this stage because of the significant investment in new infrastructure for north campus district heating.

Table 1. Project Scenarios

PROJECT TYPE	PROJECT SIZE	PROJECT FOCUS
Project Scenario 1: Biomass to Heat	20 MMBtu/hr	South Campus Heating and Cooling Plant
Project Scenario 2: Biomass to Electricity - Behind the Meter	2.5 MW	To Feed the North Campus Electric Meter
Project Scenario 3: Biomass to Electricity - Total Campus Power Generation	10 MW	To Provide All NAU Campus Electricity

Project Scenario 1 would be located at the South Campus Heating and Cooling Plant and may utilize either direct combustion or gasification technology. The project size was selected such that the biomass boiler would meet approximately 70 percent of the annual peak heating demand. This configuration allows for natural gas boilers, which can cycle faster than biomass boilers, to provide peak demand on an as-needed basis while also reducing the overall project cost by limiting the boiler size. Space is a constraining factor for this project.

Project Scenario 2 would be located east of Lone Tree Road. The project size was selected based on electricity demand at the North Campus electric meter. Data from the meter indicated only four 15-minute intervals with power demand of less than 3 MW over a one-year span. The 2.5

MW project size was selected to allow the North Campus meter to maintain the existing Arizona Public Service (APS) rate schedule, thereby minimizing the project's impacts on electric rates.

Project Scenario 3 would be located east of Lone Tree Road. The project size was selected to accommodate NAU's campus power demand with room for growth. This project scenario is based on the assumption that the biomass plant will provide electricity only for NAU and will not generate additional electricity for sales to APS.[1]

Biomass Resource Availability

The Biomass Resource Availability Review found that there is approximately 133,405 bone dry tons (BDT) practically available per year within a 50-mile radius of Flagstaff. Of the total biomass availability, 86% is from forest-sourced material and the remainder is from forest products manufacturing. Urban wood is not available within the Feedstock Study Area (FSA). The total feedstock availability within the FSA is sufficient for an 8 MW power plant with a 2:1 feedstock coverage ratio. For a 10 MW facility, the coverage ratio is 1.7:1; however, reaching beyond the 50-mile FSA would likely provide sufficient feedstock to meet a 2:1 coverage ratio.

Feedstock prices are expected to range from $20 to $30 per BDT for biomass from forest products manufacturing and $30 to $60 for biomass from forest operations. A summary of the biomass availability is shown in Table 2.

Table 2. Biomass Availability

BIOMASS MATERIAL SOURCE	BIOMASS AVAILABILITY (BDT/YEAR)	BIOMASS PRICING	
		LOW RANGE ($/BDT)	HIGH RANGE ($/BDT)
Forest Operations	114,505	$30	$60
Forest Products Manufacturing	18,900	$20	$30
Urban Wood Waste	0	$25	$30
TOTAL	**133,405**		

Bioenergy Development Opportunities

The Bioenergy Development and Technology Analysis focused primarily on biomass-to-electricity and biomass-to-heat projects. Biomass to biomethane, torrefaction, and advanced biofuels (transportation fuels) were found to be inappropriate for the energy demand at NAU based on insufficient onsite demand.

[1] Per direction from the NAU project team – in person meeting with Nick Koressel, Avi Henn, Eli Lauren-Bernstein, October 10, 2013.

Three project scenarios were reviewed:

- Project Scenario 1: Biomass to Heat – 20 MMBtu per hour – 5,317 BDT per year;
- Project Scenario 2: Biomass to Electricity – 2.5 MW – 18,615 BDT per year; and
- Project Scenario 3: Biomass to Electricity – 10 MW – 74,460 BDT per year.

TSS identified technology vendors and developers for each project scenario with experience in bioenergy development appropriate to the project's scale.

Air Emissions Impacts

A lifecycle approach was used to identify the air emissions impacts of each of the bioenergy development scenarios. The biomass lifecycle framework began when the biomass feedstock was diverted from business-as-usual practices (e.g., after the slash pile was created for pile and burn or after sawmill residuals are collected). No emissions savings were associated with the utilization of biomass from forest products manufacturing. The natural gas lifecycle includes procurement from a gas reserve within North America and the electricity lifecycle begins with the production of electricity at the power plant.

Bioenergy development was found to result in minimal regional air emissions benefits across all project types. The air emissions impacts were largely determined by the Four Forest Restoration Initiative (4FRI) business-as-usual practices limiting pile and burn activities. A summary of the findings for criteria pollutants is shown in Table 3.

Table 3. Net Criteria Emissions Impacts of Biomass Development

	CO	NO_x	PM	VOC	CH_4
PROJECT SCENARIO 1: 20 MMBtu (TPY)	5.9	4.6	8.0	-1.4	-2.4
PROJECT SCENARIO 2: 2.5 MW (TPY)	-624.6	-26.3	-63.8	-51.3	-32.0
PROJECT SCENARIO 3: 10 MW (TPY)	-2,116.3	-89.0	-216.2	-173.7	-108.6

TSS found, in coordination with NAU's Office of Compliance,[2] that Project Scenarios 1 and 2 are expected to fit within the existing air permit held by NAU. Project Scenario 3 would push NAU above the Major Source permit threshold.

Greenhouse gas offsets are calculated using Clean Air-Cool Planet Campus Carbon Calculator. The calculator assumes no carbon footprint for the utilization of wood chips. Table 4 shows the potential impacts of greenhouse gas reductions based on the Clean Air-Cool Planet Campus Carbon Calculator given the 2012 base of 61,595 metric tonnes (MT) of CO_2e.[3]

[2] Jim Biddle, Manager of Environmental and Industrial Hygiene Programs.
[3] TSS was not provided access to NAU's filled-out Clean Air-Cool Planet Campus Carbon Calculator; 61,595 is based on communication with NAU project team.

Table 4. Potential for Greenhouse Gas Offsets[4]

	POTENTIAL CARBON REDUCTION (MT CO_2e)	PERCENT REDUCTION
PROJECT SCENARIO 1	3,292	5.3%
PROJECT SCENARIO 2	10,111	16.4%
PROJECT SCENARIO 3	33,155	53.8%

Economic Analysis

The economics of bioenergy projects at NAU are challenging at this time due primarily to the relatively low cost of natural gas and electricity. Currently, there are no incentives available from APS to produce electricity from biomass for onsite load.[5] The findings of the financial analysis for Project Scenario 1 are available in Table 5.

Table 5. Financial Analysis for Biomass-to-Heat Projects

NATURAL GAS PRICE ($/THERM)	INTERNAL RATE OF RETURN	SIMPLE PAYBACK PERIOD (YEARS)
$0.56[6]	1.8%	23.6
$0.80[7]	9.3%	12.7
$1.81[8]	55.8%	4.3

Project Scenario 2 and 3 are challenging at this point in time without a financial incentive for producing biomass power either from APS or in the form of financial compensation for carbon offsets. The financial analysis was therefore performed to identify the levelized price of electricity that would be appropriate for NAU to consider biomass-to-electricity projects given a variety of feedstock prices (Table 6).

---

[4] Calculated with Clean Air-Cool Planet Campus Carbon Calculator based on APS average electricity blend and the projected load displacement per the Energy Load Assessment.
[5] Brenda Hazlett, Arizona Public Service Relationship Manager – Northeast Division.
[6] Lowest price since 2000 based on Figure 28 and NAU's price structure.
[7] Current price, as directed by the NAU project team.
[8] Highest price since 2000 based on Figure 28 and NAU's price structure.

Table 6. Financial Analysis for Biomass-to-Electricity Projects

FEEDSTOCK PRICE ($/BDT)	PROJECT SCENARIO 2: LEVELIZED COST OF ELECTRICITY ($/KWH)	PROJECT SCENARIO 3: LEVELIZED COST OF ELECTRICITY ($/KWH)
$0	$0.127	$0.084
$10	$0.137	$0.094
$20	$0.146	$0.104
$30	$0.156	$0.113
$40	$0.166	$0.123

As shown in Table 6, there are significant economies of scale between the small-scale and large-scale projects, most significantly the ability to utilize waste heat to help offset natural gas demand for campus heating. With feedstock prices expected to be $28/BDT, the required levelized price for Project Scenario 2 and 3 remains higher than the anticipated avoided cost from purchasing APS power. NAU should monitor the development of the carbon market which could considerably increase project viability (however, existing carbon markets worldwide have been unstable).

Recommendations and Next Steps

Bioenergy development in Arizona is challenging largely due to the availability of relatively low-cost natural gas and electricity. However, the Flagstaff area is surrounded by biomass resources predominantly through the 4FRI stewardship contract. NAU is in an optimal position to utilize the available biomass, consequently supporting local forest management and increasing their utilization of renewable energy. TSS recommends the following steps to move forward with bioenergy development.

- Keep in touch with Good Earth Power, as there may be partnership opportunities that would help reduce the capital cost of a project and/or facilitate delivery of reduced cost feedstock.
- Start small; there is a learning curve when transitioning from natural gas to biomass. Small projects tend to allow greater flexibility and time for operations staff to learn the biomass model.
- TSS recommends Project Scenario 1 for next steps as the most economically attractive model.
- Consider reaching out to Good Earth Power to initiate discussions regarding a long-term feedstock purchase and sale agreement.
- Structured outreach and communication to the NAU and Flagstaff communities will be critical to community acceptance.
- Consider applying for the Woody Biomass Utilization Grant from the USFS for funding engineering and design work.
- NAU may want to monitor the rapidly expanding biochemical/advanced biofuels market due to their location amidst a significant forest biomass resource and the potential to partner with a biochemical/biofuels manufacturer to provide a unique opportunity for student and university research.

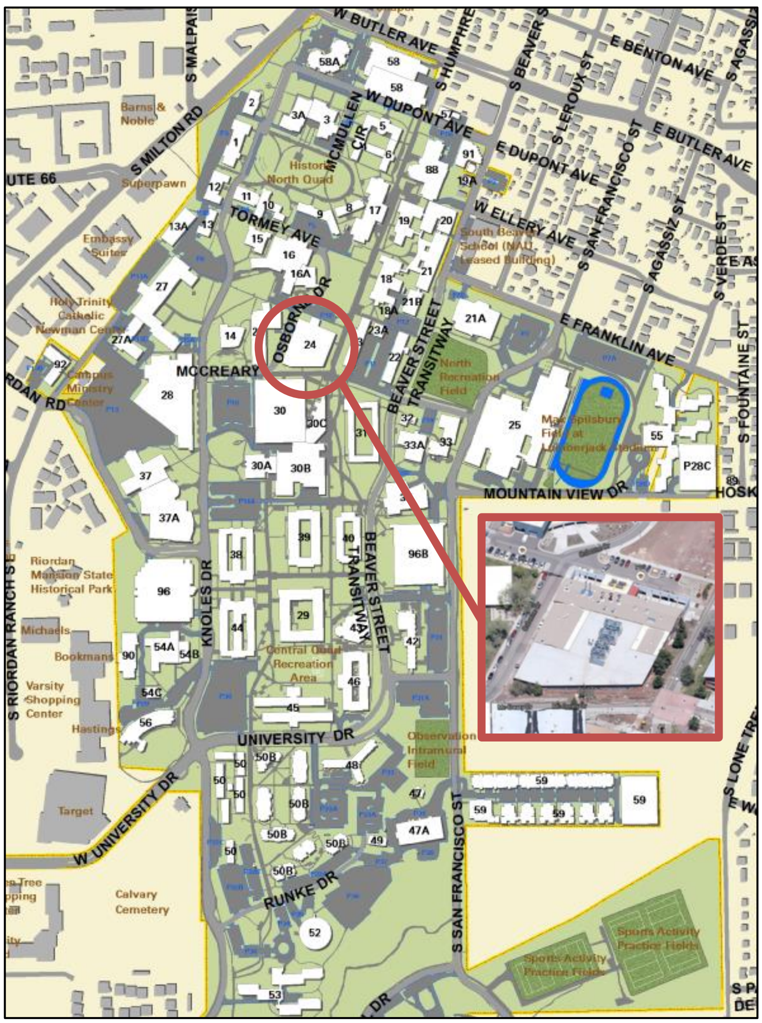
ENERGY LOAD ASSESSMENT

The energy load analysis is used to develop a better understanding of the energy use patterns at the NAU campus. The findings help to guide the selection and size of potential bioenergy facilities. TSS reviewed the natural gas and electricity use over the last five years (when available).

Campus Layout

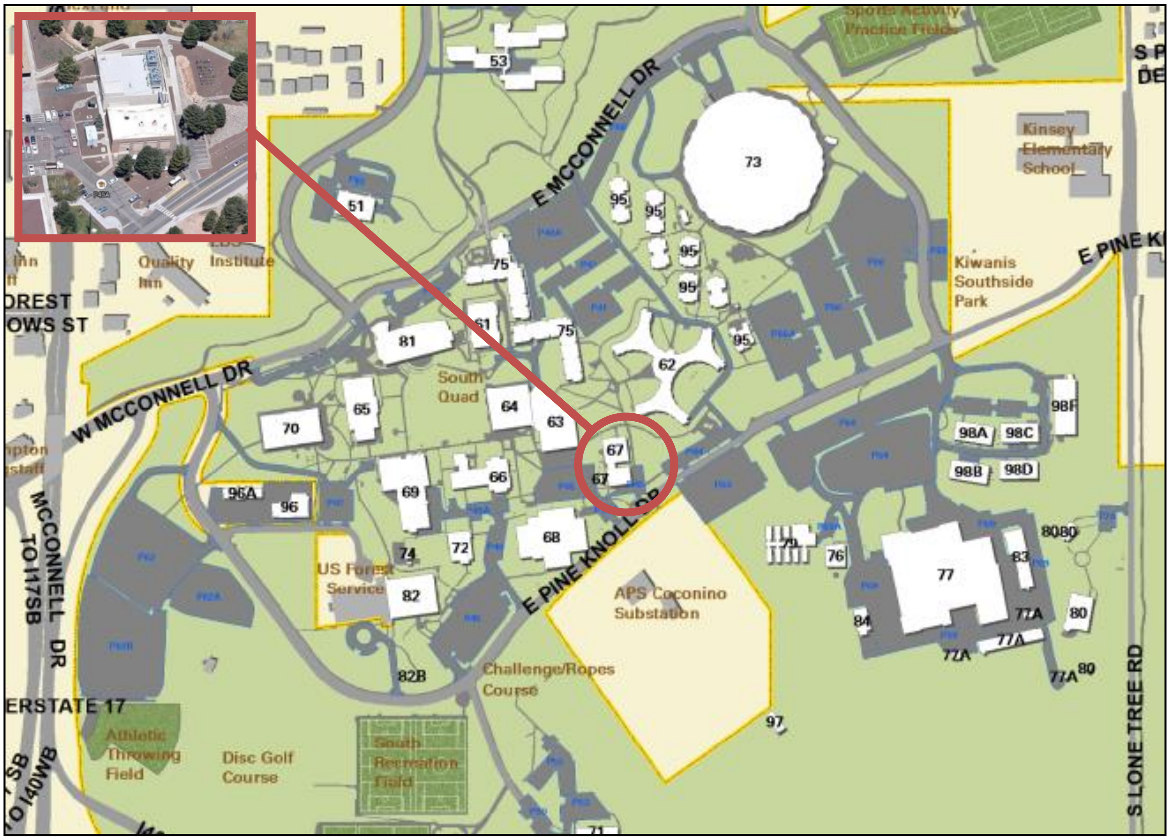
The north campus is generally defined as the portion of NAU campus located to the north of McConnell Drive and to the west of Lone Tree Road (Figure 1). The north campus is heated and cooled using district heating and cooling located in building 24. An aerial photograph of the North Campus Heating and Cooling Facility is located in the inset within Figure 1.

Figure 1. Northern Arizona University North Campus



The south campus is generally defined as the portion of NAU campus located to the south of McConnell Drive and to the west of Lone Tree Road (Figure 2). The south campus is heated and cooled using district heating and cooling located in building 67. An aerial photograph of the South Campus Heating and Cooling Facility is located in the inset within Figure 2.

Figure 2. Northern Arizona University South Campus



The campus electricity is provided by APS and is monitored by two meters, one each for the North Campus and the South Campus. The meters are both located at the APS Coconino Substation shown just south of the South Campus Heating and Cooling Plant (Figure 2). Prior to 2012, the electricity ran through one meter.

Campus Heat Demand

<u>North Campus Heat Load</u>

The North Campus Heating and Cooling Plant houses three natural gas boilers each producing high pressure rated at 50,000 pounds per hour of steam. Two of the units were manufactured in 2010 and one unit in 2012. The units were installed at NAU in 2012. Due to the relatively new infrastructure in place at the North Campus Heating and Cooling Plant, this study will not analyze the heat demand for the north campus.[9]

[9] Per NAU project team request.

South Campus Heat Load

The South Campus Heating and Cooling Plant houses three natural gas boilers each producing hot water:

- Universal boiler manufactured in 2000 and is rated for 25,000 MBH[10] input;
- Cleaver-Brooks boiler manufactured in 1975 with a retrofit Iron Fireman burner rated for 25,000 MBH input; and
- Cleaver-Brooks boiler manufactured in 1970 rated for 57,394 MBH input.

The Universal boiler nameplate efficiency is 80.3% efficient. For the purposes of this analysis, the other two boilers will be assumed to operate under the same efficiency rating.

NAU staff provided monthly natural gas consumption data for the boilers at the South Campus Heating and Cooling Plant for the previous five years. Additionally, daily natural gas meter readings were provided for January 1, 2011 through July 31, 2013. The data provided is summarized in Table 7.

Table 7. South Campus Historic Natural Gas Consumption

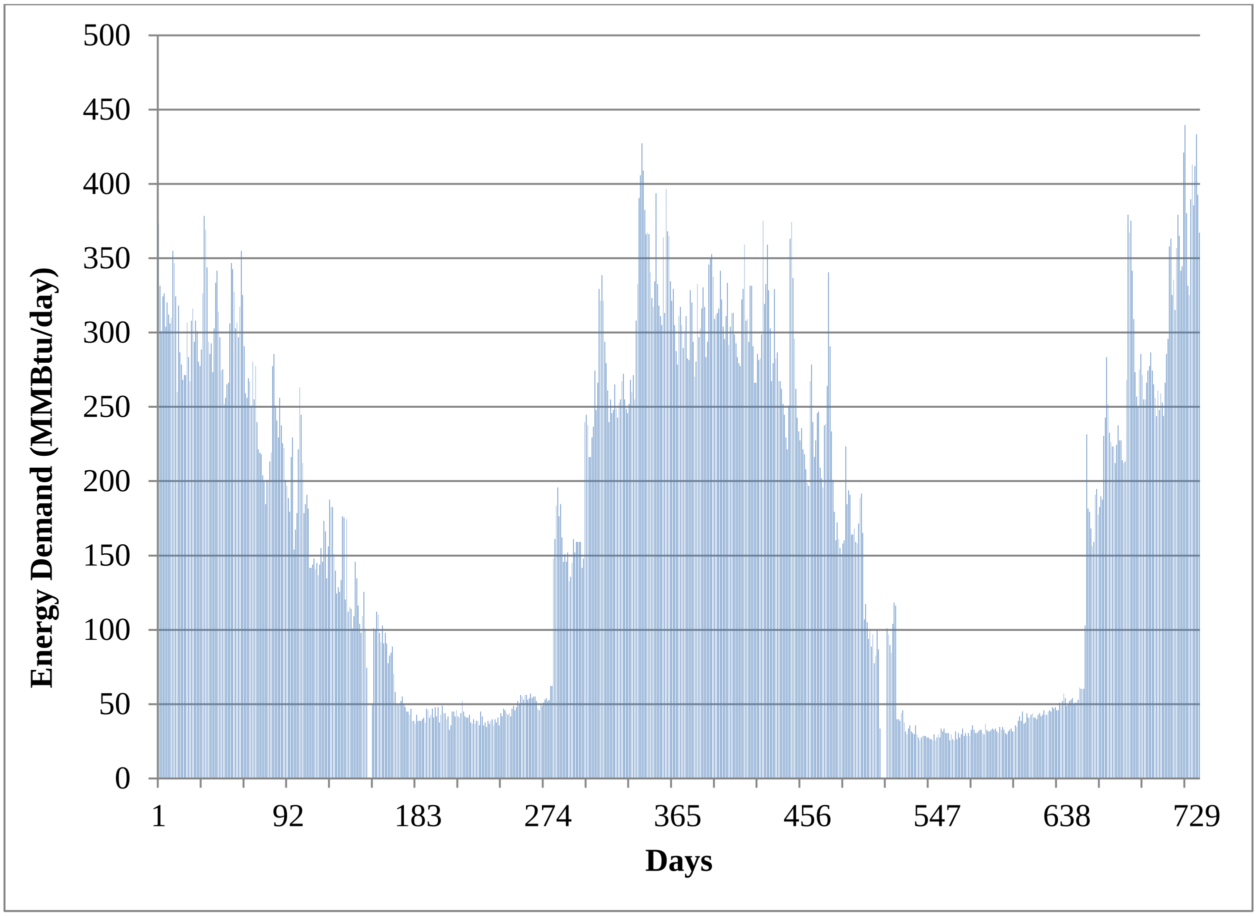
	2008 (MSCF[11]/ MONTH)	2009 (MSCF/ MONTH)	2010 (MSCF/ MONTH)	2011 (MSCF/ MONTH)	2012 (MSCF/ MONTH)	AVERAGE (MSCF/ MONTH)	AVERAGE DAILY DEMAND (MSCF/DAY)
January	10,402	9,528	10,028	9,236	9,477	9,734	314.0
February	8,829	8,616	8,360	8,474	8,657	8,587	306.7
March	7,984	7,813	8,542	7,332	8,334	8,001	258.1
April	6,435	6,748	6,785	5,157	6,296	6,284	209.5
May	3,358	2,752	4,062	3,542	3,152	3,373	108.8
June	1,106	1,852	1,431	2,065	1,012	1,493	49.8
July	1,022	807	1,159	1,281	922	1,038	33.5
August	1,152	989	1,323	1,218	1,032	1,143	36.9
September	1,343	1,077	1,459	1,487	1,342	1,342	44.7
October	5,425	5,775	4,844	4,748	4,509	5,060	163.2
November	6,998	7,449	8,044	7,837	7,898	7,645	254.8
December	9,462	10,189	8,325	10,442	10,327	9,749	314.5
TOTALS	**63,516**	**63,595**	**64,362**	**62,819**	**62,958**	**63,450**	**173.8**

[10] MBH = one thousand British thermal units (Btu) per hour. One Btu = the amount of energy needed to cool or heat one pound of water by one degree Fahrenheit.
[11] MSCF = one thousand standard cubic feet.

Through discussions with NAU staff,[12] the Universal boiler is primarily used in the summer because of its lower turndown capabilities, and the 1975 Cleaver-Brooks boiler is used in the winter with the Universal boiler to provide peaking capacity. The 1970 Cleaver-Brooks boiler is maintained as redundancy. With the retrofit of the 1975 Cleaver-Brooks boiler, there are no near-term plans to replace any of the natural gas boilers.

The daily meter readings from January 1, 2011 until December 31, 2012 were utilized to develop an energy load profile. The daily natural gas consumption is shown in Figure 3. Note there is a period of 48 hours each year where the boilers are shut down for scheduled maintenance. These periods occur in May and are seen near day marker 151 and 501.

Figure 3. South Campus Daily Natural Gas Consumption, 2011 to 2013



TSS utilized loading factors to simulate hourly demand based on average daily consumption (see Figure 4).[13] Hourly simulation captures the fluctuation of heat demand over the course of a day and provides additional detail to calculate the capacity factor. The projected hourly demand is ordered by magnitude spanning the five years to provide the heat demand curve (Figure 5).

---

[12] Lindsay Wagner, Director of Energy Services and Sustainability and Mike Talbsot, Facilities Operator.
[13] Pedersen, L. *Load Modelling of Buildings in Mixed Energy Distribution Systems*. Norwegian University of Science and Technology. February 2007.

Figure 4. Thermal Energy Daily Load Factors

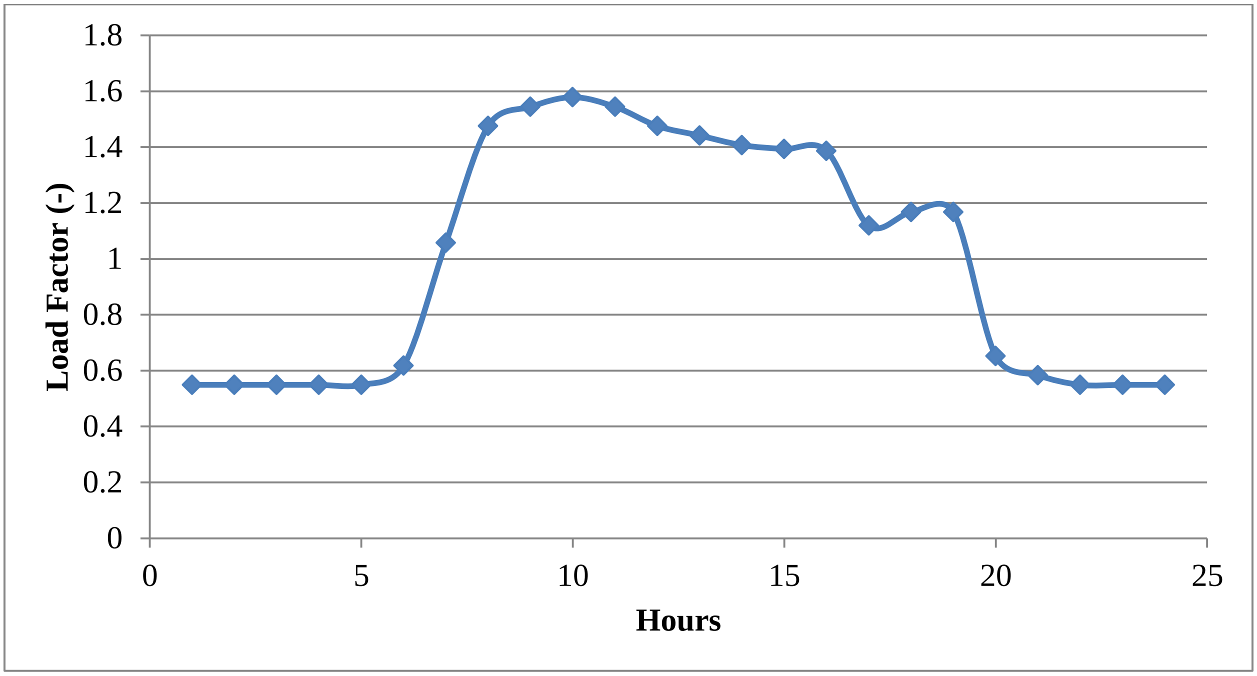
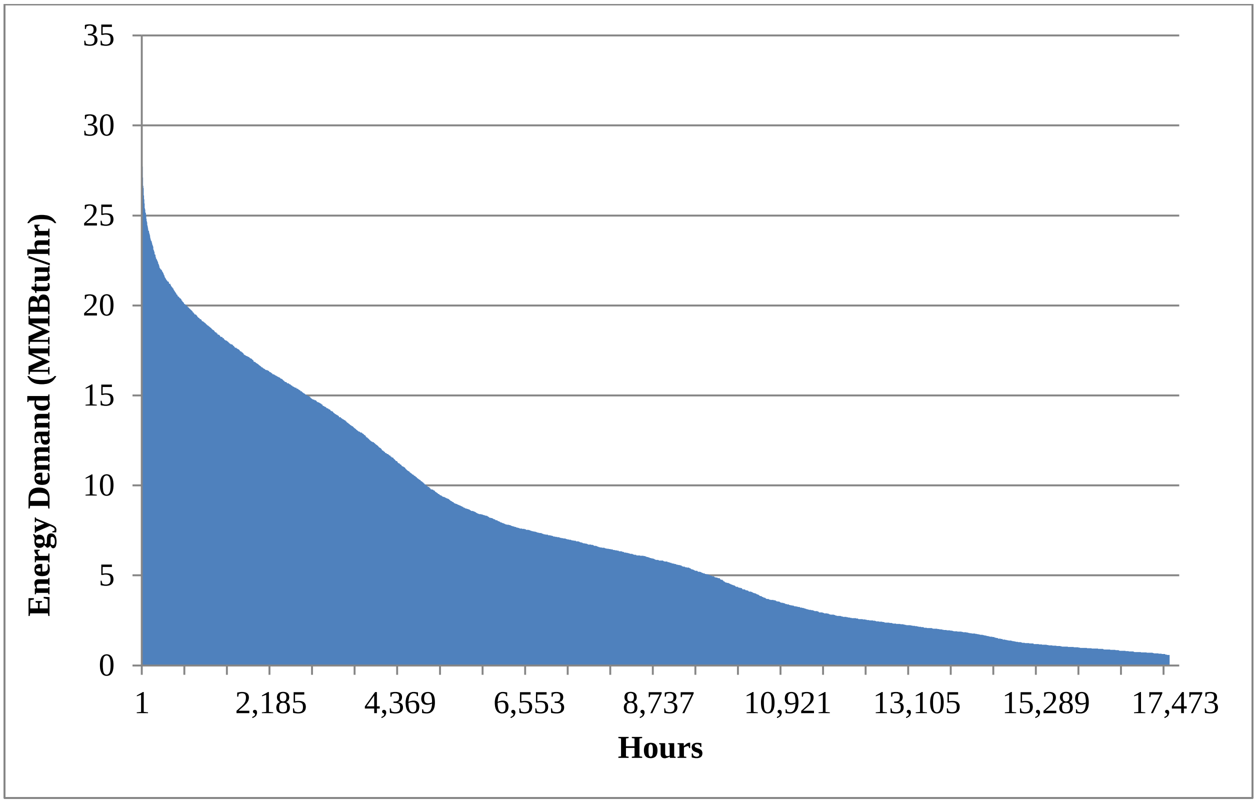


Figure 5. South Campus Hourly Projected Natural Gas Consumption, 2011 to 2012



Based on the projections in Figure 5, the highest peak load is approximately 28 MMBtu per hour. Using this curve, the impact of a biomass thermal unit can be estimated as shown in Table 8 and Figure 6.

Table 8. Impact of South Campus Biomass Thermal Unit Sizing

BOILER SIZE (MMBTU/HR)	CAPACITY FACTOR[14] (%)	NATURAL GAS DISPLACED (MSCF/YEAR)	PERCENTAGE OF TOTAL DEMAND
5	74.0	31,756	50.5%
10	56.5	48,546	77.2%
15	45.0	57,970	92.2%
20	36.2	62,098	98.7%
25	29.3	62,849	99.9%
30	24.4	62,889	100%

Figure 6. Impact of South Campus Biomass Thermal Unit Sizing

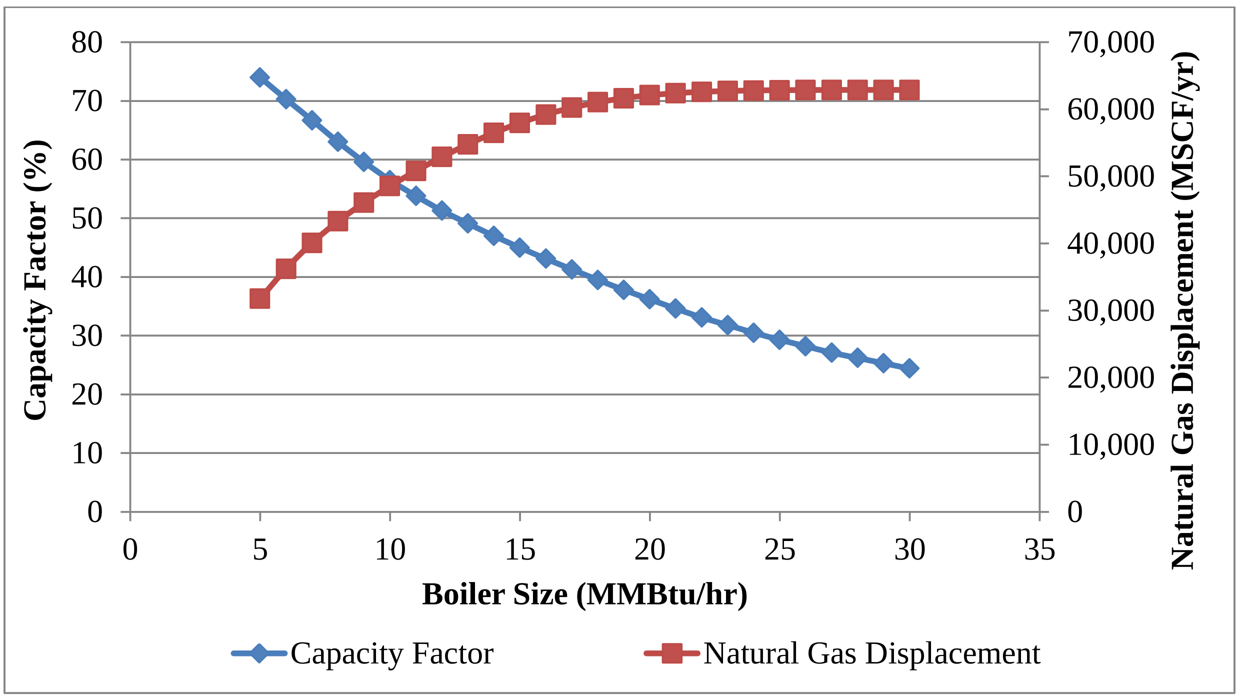


Table 8 and Figure 6 demonstrate declining capacity factor relative to project size. Biomass thermal units, like any energy system, are more cost effective with a higher capacity factor. To maximize the cost saving potential of a biomass system, the facility size must be balanced to capture the maximum fossil-fuel displacement while achieving a cost effective capacity factor. This relationship will be further evaluated in the Economic Analysis section.

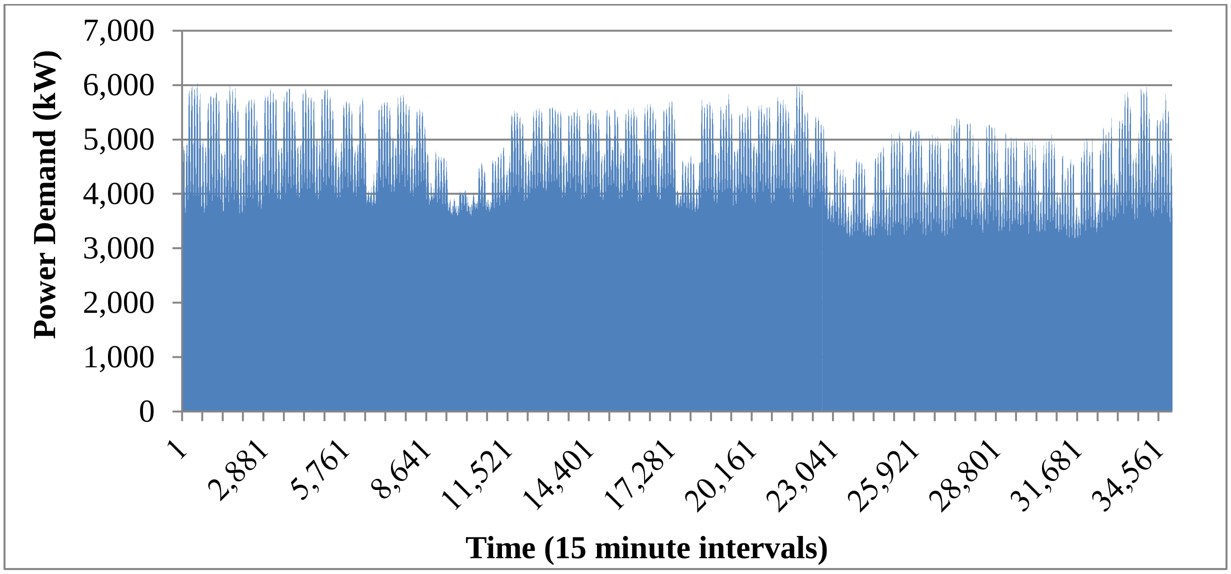
[14] Calculates the maximum potential capacity factor for a facility not accounting for regular scheduled maintenance.

Campus Electricity Demand

North Campus Electricity Load

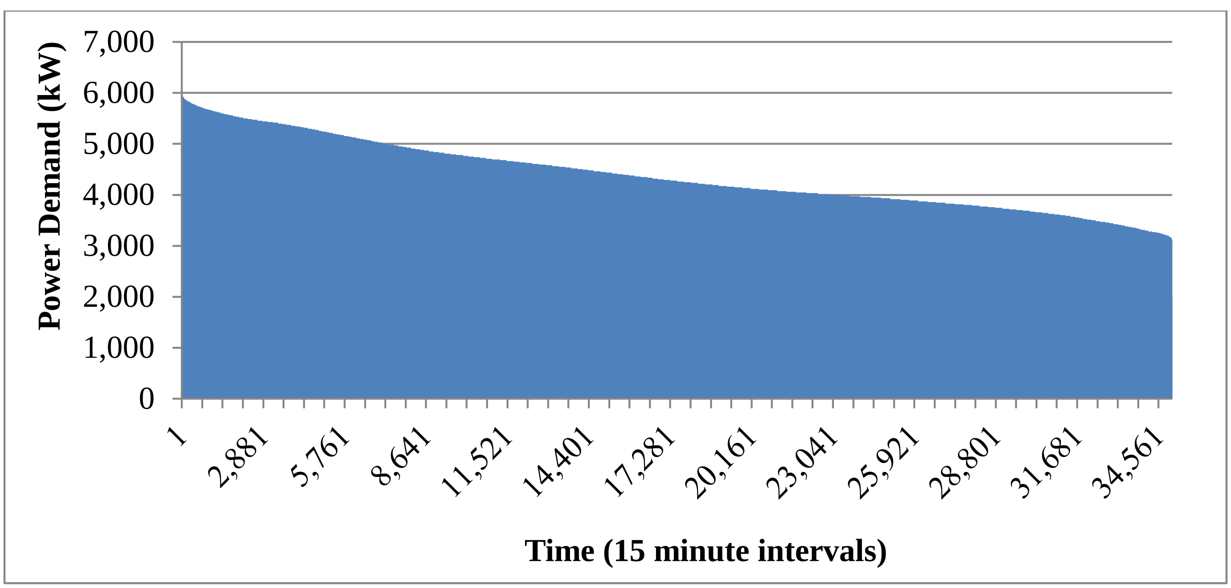
North campus electricity is provided by APS and is served through a separate meter than the south campus. Electricity use data was provided by APS; however, the north and south campus have only been on separate meters since September 14, 2012. Figure 7 shows one year of electricity data for the north campus in 15-minute demand intervals.

Figure 7. North Campus Electricity Use, September 2012 to September 2013



Organizing the data in Figure 7 by magnitude provides the electricity load profile for the north campus (Figure 8). As with the heat load profile, the electricity load profile is used to understand the effects of project size on energy use.

Figure 8. North Campus Electricity Load Profile, September 2012 to September 2013

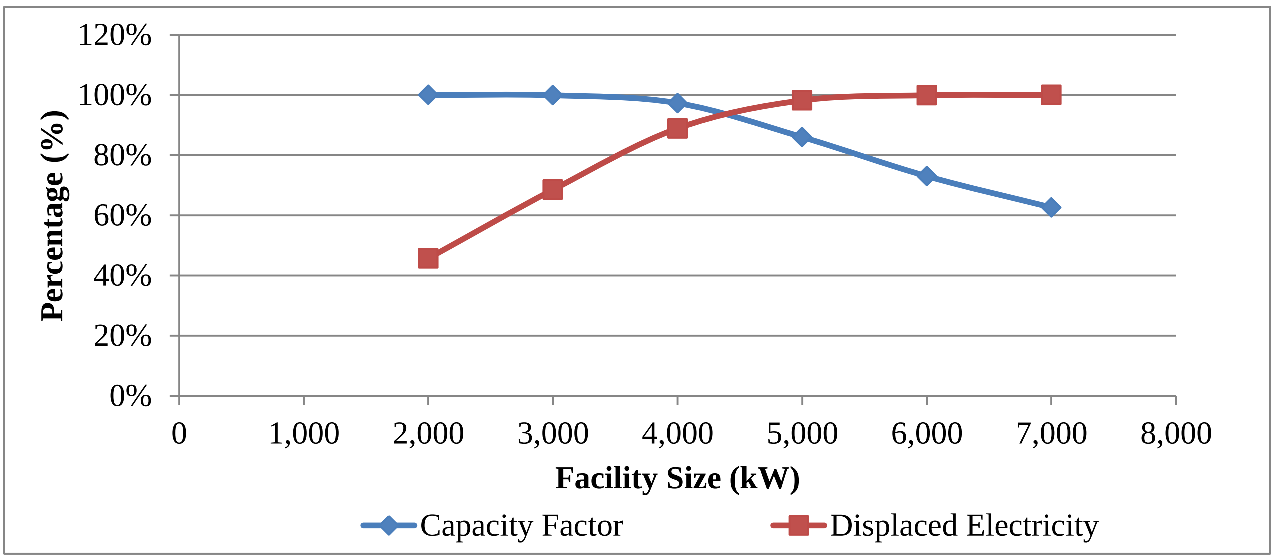


Based on projections in Figure 8, the highest peak load is approximately 6,034 kW and the annual energy consumption is 28,375 MWh. Using this curve, the impact of a biomass electricity facility can be estimated as shown in Table 9 and Figure 9.

Table 9. Impact of North Campus Biomass Electricity Facility Sizing

FACILITY SIZE (KW)	CAPACITY FACTOR[15] (%)	ELECTRICITY DISPLACED (MWH/YEAR)	PERCENTAGE OF TOTAL DEMAND
2,000	100%	17,520	45.7%
3,000	99.9%	26,279	68.5%
4,000	97.3%	34,106	88.9%
5,000	86.0%	37,674	98.2%
6,000	73.0%	38,375	99.9%
7,000	62.6%	38,375	100%

Figure 9. Impact of North Campus Biomass Electricity Facility Sizing



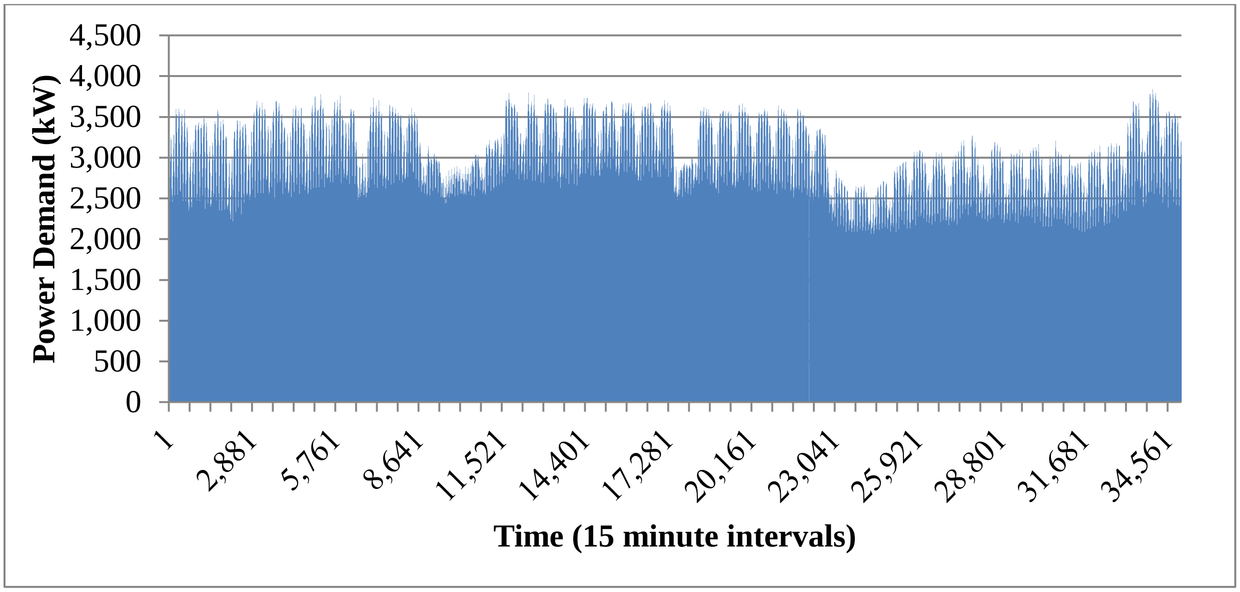
Biomass electricity facilities, like any energy system, are more cost effective with a higher capacity factor. Based on Table 9 and Figure 9, a 3 MW or smaller project would be able to provide baseload power to the north campus. The load profile indicates that there is relatively consistent electricity demand throughout the year. The consistent energy demand is beneficial for renewable energy development.

[15] Calculates the maximum potential capacity factor for a facility not accounting for regular scheduled maintenance.

South Campus Electricity Load

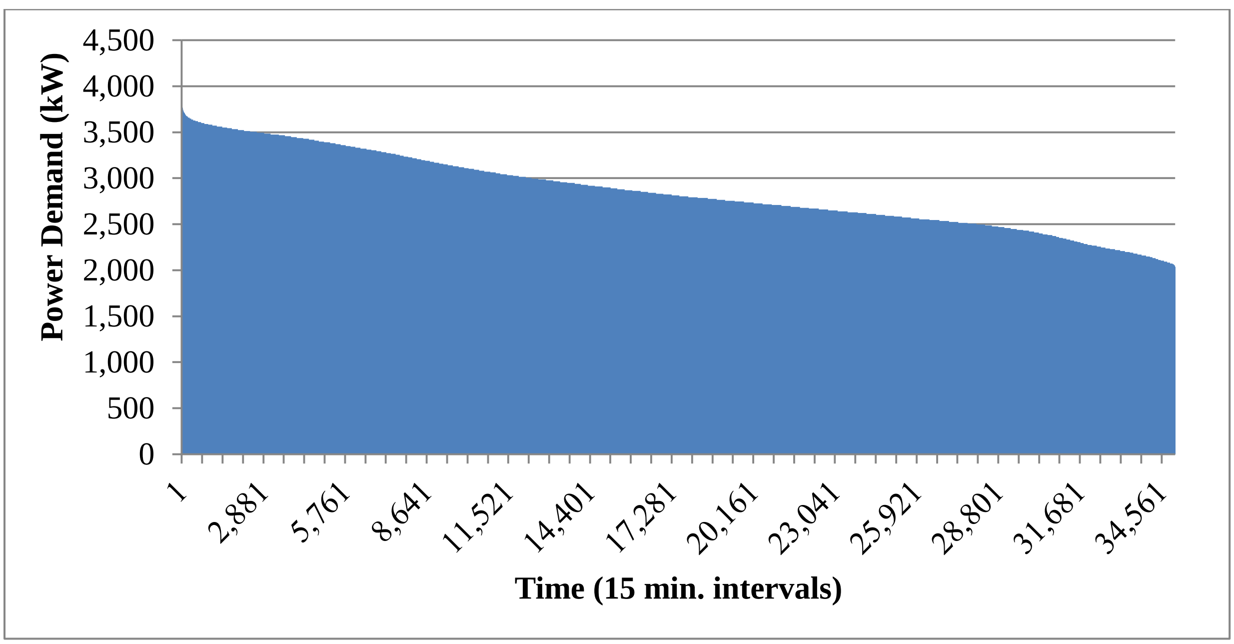
South campus electricity is provided by APS and is served through a separate meter than the north campus. Electricity use data was provided by APS for the south campus meter since the separation of the meters on September 14, 2012 (Figure 10).

Figure 10. South Campus Electricity Use, September 2012 to September 2013



Organizing the data in Figure 10 by magnitude provides the electricity load profile for the south campus (Figure 11). As with the heat load profile, the electricity load profile is used to understand the effects of project size on energy use.

Figure 11. South Campus Electricity Load Profile, September 2012 to September 2013

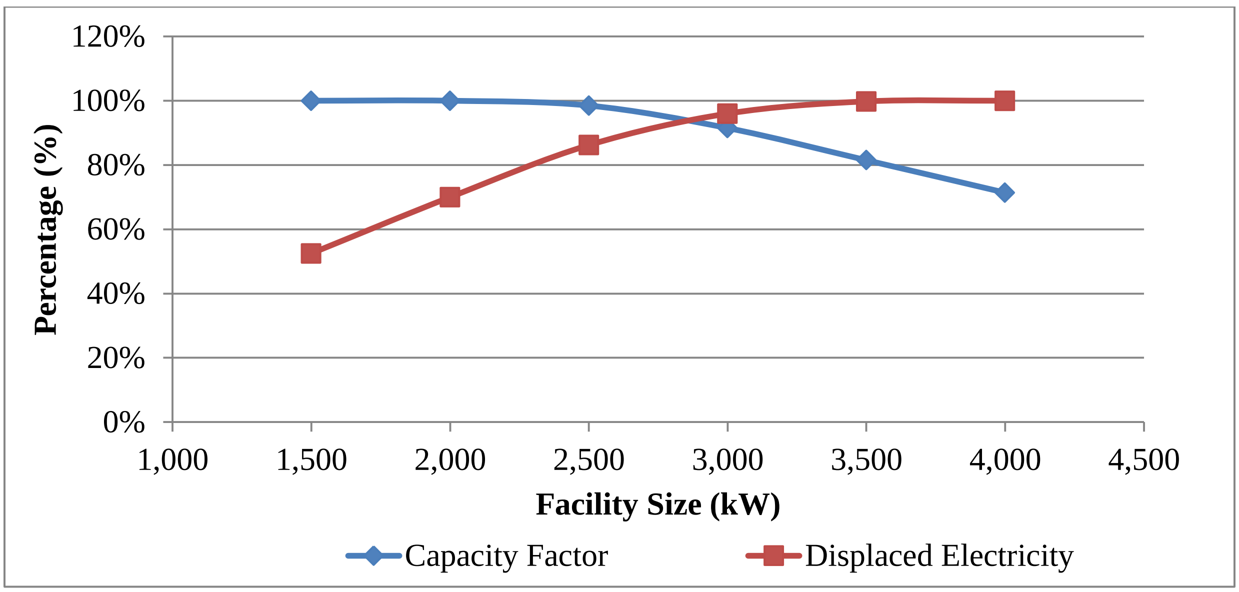


Based on the projections in Figure 11, the highest peak load is approximately 3,840 kW and the annual energy consumption is 25,028 MWh. Using this curve, the impact of a biomass electricity facility can be estimated as shown in Table 10 and Figure 12.

Table 10. Impact of South Campus Biomass Electricity Facility Sizing

FACILITY SIZE (KW)	CAPACITY FACTOR [16] (%)	ELECTRICITY DISPLACED (MWH/YEAR)	PERCENTAGE OF TOTAL DEMAND (%)
1,500	100%	13,140	52.5%
2,000	100%	17,520	70.0%
2,500	98.5%	21,563	86.2%
3,000	91.5%	24,032	96.0%
3,500	81.5%	24,980	99.8%
4,000	71.4%	25,028	100%

Figure 12. Impact of South Campus Biomass Electricity Facility Sizing



Based on Table 10 and Figure 12, a 2 MW project would be able to provide baseload power to the south campus. For projects over 2 MW, some power would be expected to feed back to the APS grid unless the project has the ability to load follow. The data show a relatively consistent energy demand which is attractive for bioenergy development.

<u>All Campus Electricity</u>

Combining the data from the north and south campus meter provides the electricity demand for the entire campus. Figure 13 shows the total NAU campus electricity demand. Organizing the data in Figure 13 by magnitude provides the electricity load profile for the NAU campus (Figure 14).

[16] Calculates the maximum potential capacity factor for a facility not accounting for regular scheduled maintenance.

Figure 13. NAU Campus Electricity Use, September 2012 to September 2013

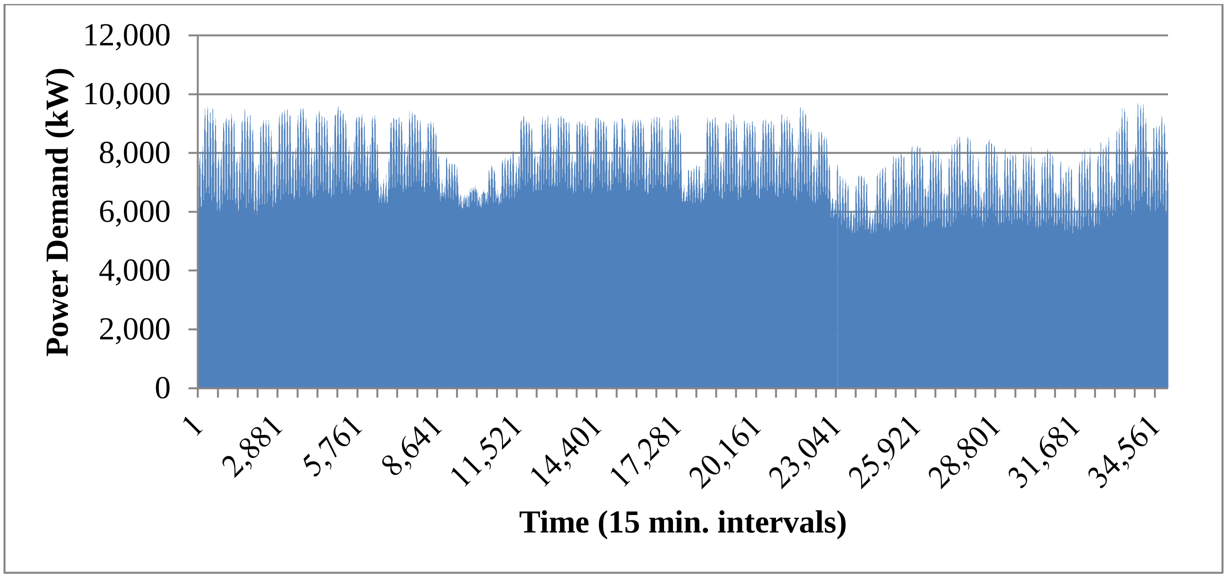
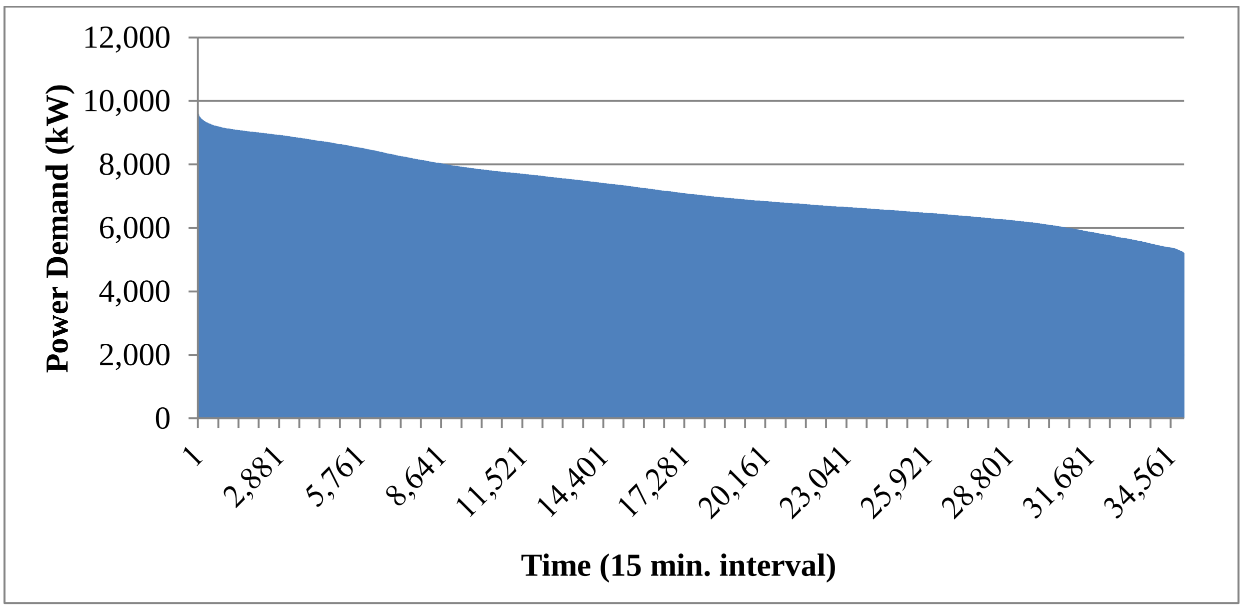


Figure 14. NAU Campus Electricity Load Profile, September 2012 to September 2013



Based on the data in Figure 14, the highest peak load is approximately 9,700 kW. Using this curve, the impact of a biomass electricity facility can be estimated as shown in Table 11.

Table 11. Impact of NAU Campus Biomass Electricity Facility Sizing

FACILITY SIZE (KW)	CAPACITY FACTOR [17] (%)	ELECTRICITY DISPLACED (MWH/YEAR)	PERCENTAGE OF TOTAL DEMAND
5,000	100	43,800	69.1%
6,000	99.3	52,206	82.3%
7,000	95.4	58,493	92.3%
8,000	88.3	61,868	97.6%
9,000	80.3	63,312	99.9%
10,000	72.4	63,403	100%

To cover the entire campus load, a 10 MW facility would be recommended. As shown in Table 11 and Figure 14, the overall campus electricity profile has a relatively consistent electricity demand with a capacity factor of 72.4 percent if the facility is sized to meet all of campus demand. A high capacity factor is important for the financial viability of a project, as the capital cost can be amortized over greater energy production.

Findings

The Energy Load Analysis identified three potential opportunities for bioenergy development. Optimal project sizes to fit within campus property are shown in Table 12. The North Campus Heating and Cooling Plant was not considered a viable option for bioenergy development at this stage because of the significant investment in new infrastructure for north campus district heating.

The South Campus Heating and Cooling Plant provides an opportunity for bioenergy utilization up to 20 MMBtu per hour. The heat from a bioenergy facility would displace natural gas consumption and would replace one of the existing natural gas boiler units.

Small-scale biomass to electricity development is optimal for the North Campus electric meter due to the high baseload demands. A 2.5 MW biomass to electricity facility could augment the baseload power draw without affecting the electricity rate schedule currently utilized by NAU (See Economic Analysis for more details).

Large-scale biomass to electricity development is an option to power the entire campus when scaled at 10 MW.

Table 12. Optimal Project Sizes

PROJECT TYPE	PROJECT SIZE
Biomass to Heat	20 MMBtu/hr
Biomass to Electricity: Behind the Meter	2.5 MW
Biomass to Electricity: Total Power Generation	10 MW

[17] Calculates the maximum potential capacity factor for a facility not accounting for regular scheduled maintenance.

BIOMASS RESOURCE AVAILABILITY REVIEW

A biomass fuel supply assessment was completed by TSS for the Greater Flagstaff Forest Partnership in 2002. This review was undertaken to determine the potential availability and delivered cost of woody biomass fuel material for use in a biomass power generation facility located at Bellemont, Arizona (approximately 10 miles west of Flagstaff). While the 2002 assessment is almost a dozen years old, key findings (e.g., seasonal availability of forest residuals, biomass recovery factors, facilities utilizing biomass material) were helpful in the development of this 2013/2014 review targeting a bioenergy facility at NAU.

For this review, TSS focused on the long-term economic and environmental sustainability of forest resources. The range of potential biomass resource feedstocks reviewed includes:

- Woody biomass residuals from forest operations:
  - Timber harvest operations;
  - Fuels treatment/forest restoration projects; and
  - Timber stand improvement projects;
- Forest products manufacturing byproduct; and
- Woody biomass from urban wood waste (e.g., construction/demolition wood, pallets, tree trimmings, pine needles).

Feedstock Study Area

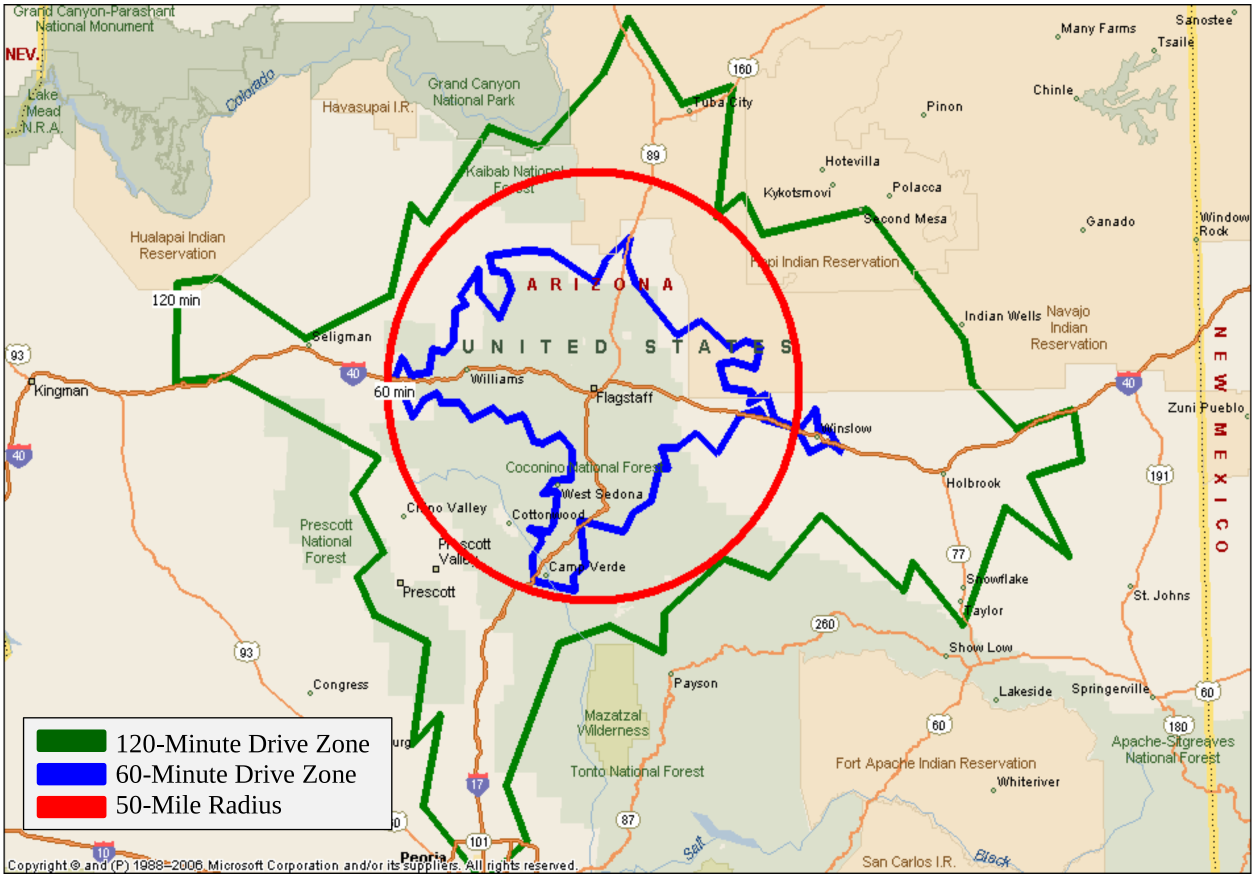
Consistent with the objectives of this biomass feedstock availability review,[18] the region located within a 50-mile radius of Flagstaff was included in the FSA. Figure 15 highlights the FSA.

Figure 15. NAU Feedstock Study Area

[18] Analyze cost effective availability of forest feedstock sourced within economical transport distance.

An important economic consideration in determining feedstock availability is the relative location of potential feedstocks to the desired destination (NAU South Campus). Transportation costs are typically the most significant expense when sourcing biomass feedstock. Figure 16 provides 60-minute and 120-minute drive time zones for the FSA. Note that most of the NAU FSA has a 60-minute or less drive time.

Figure 16. Feedstock Drive Time Zones: 60 Minute and 120 Minute



Vegetation Cover and Land Ownership/Jurisdiction

Woody biomass availability for any given region is heavily dependent on vegetation cover, land management objectives, and land ownership. Vegetation cover within the FSA is predominantly shrub and non-forested at 60%, coniferous (fir and pine stands) at 20%, and pinyon-juniper at 17% of the landscape. Figure 17 is a map showing the relative locations of the vegetation cover types within the FSA. Figure 18 and Table 13 summarize the predominant vegetation cover types.

Figure 17. Vegetation Cover within the FSA

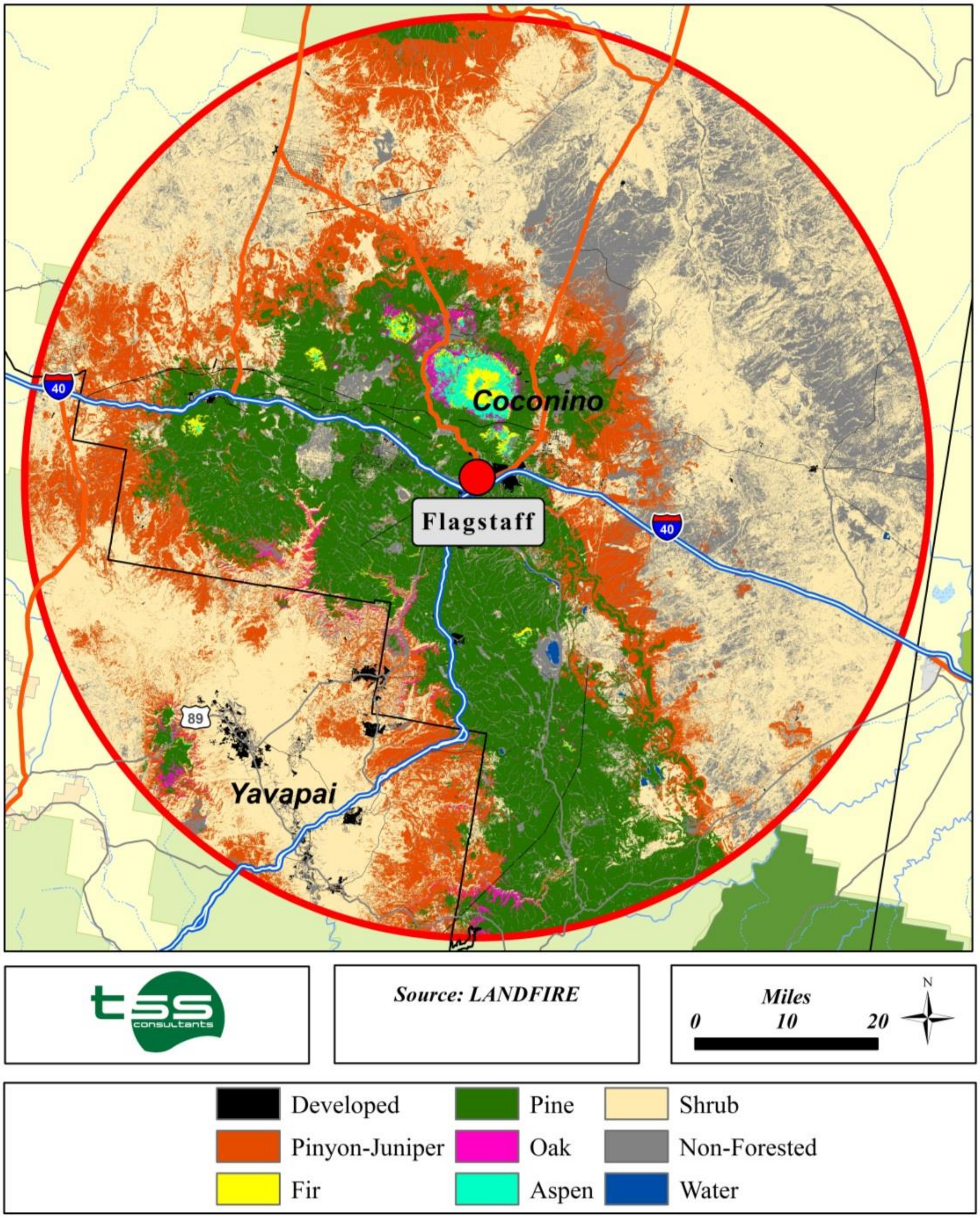


Figure 18. Vegetation Cover as a Percentage of Total Cover within the FSA

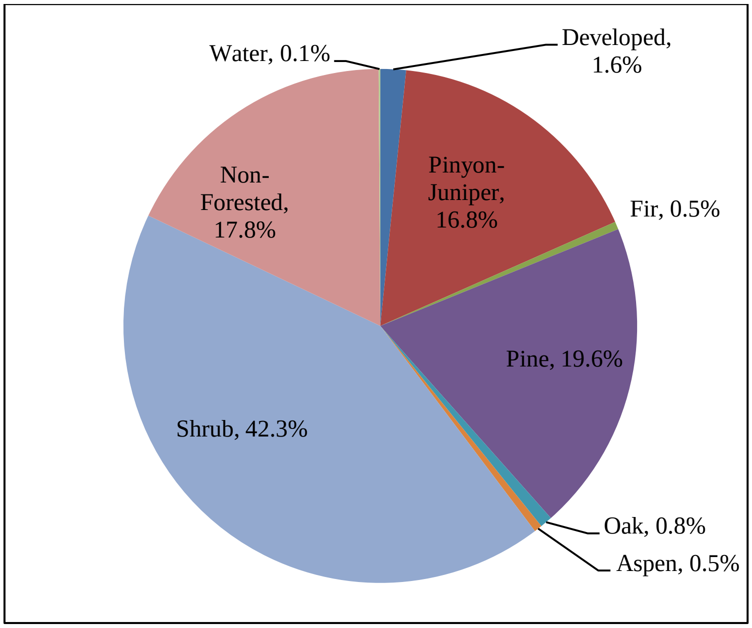


Table 13. Vegetation Cover Summary within the FSA

COVER CATEGORIES	ACRES	PERCENT OF TOTAL
Developed	80,668	1.6%
Pinyon-Juniper	842,576	16.8%
Fir	24,410	0.5%
Pine	984,566	19.6%
Oak	38,917	0.8%
Aspen	25,098	0.5%
Shrub	2,128,602	42.3%
Non-Forested	896,469	17.8%
Water	5,242	0.1%
TOTALS	5,026,548	100.0%

Land ownership drives vegetation management objectives and within the FSA, the U.S. Department of Agriculture (USDA) Forest Service (USFS) is the most significant land manager with responsibility for approximately 57% of the landscape. Private land makes up about 7% and the Bureau of Land Management (BLM) makes up 14%. Federal land management agencies (USFS and BLM) together manage approximately 70% of the landscape. Federal jurisdiction and management objectives have a significant influence on the types and volumes of woody biomass material available annually within the FSA. Figure 19 highlights the locations of the various ownerships and jurisdictions.

Figure 19. Land Ownership/Jurisdiction within the FSA

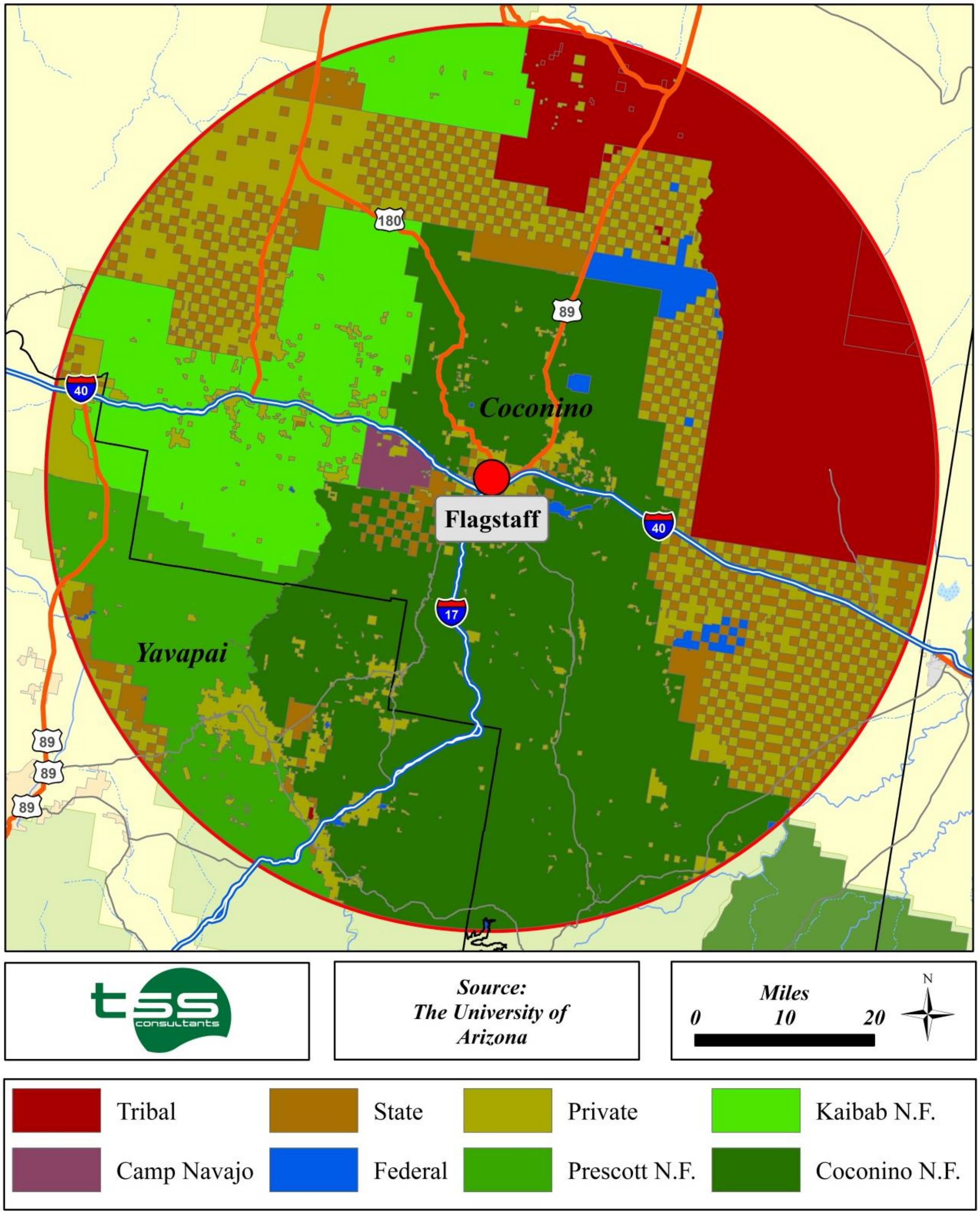


Table 14 summarizes land ownership/jurisdiction of forest vegetation cover types that could generate biomass feedstock material within the FSA. Note that other vegetation types (such as pinyon-juniper) could also provide significant volumes of biomass material.[19] However, due to the relatively high expense associated with collection and processing (chipping) of pinyon-juniper material, this potential resource was deemed uneconomical for use as feedstock for a bioenergy project at NAU.

Table 14. Land Ownership/Jurisdiction Forest Vegetation Cover within the FSA

LAND OWNER/MANAGER	FORESTED ACRES (FIR AND PINE COVER TYPES)	PERCENT OF TOTAL
Camp Navajo	18,144	1.8%
Coconino NF	673,048	66.7%
Kaibab NF	241,001	23.9%
Prescott NF	12,725	1.3%
Private	35,754	3.5%
Other Federal	2,698	0.3%
State	25,549	2.5%
Tribal	57	0.0%
TOTALS	**1,008,976**	**100.0%**

Forest Operations

Forest operations can provide significant volumes of woody biomass material. Typically available as limbs, tops, and submerchantable logs, these residuals are byproducts of commercial timber harvesting operations. In Northern Arizona, forest restoration and timber stand improvement activities are integrated with commercial timber harvest operations that generate significant volumes of harvest residuals. These residuals currently have little to no merchantable value[20] but can be a relatively economic raw material feedstock supply for value-added woody biomass utilization such as a bioenergy facility. Once collected and processed using portable chippers or grinders, this material is an excellent biomass feedstock for a bioenergy facility due to the relatively high heat value (7,800 to 8,500 Btu per dry pound) and relatively low ash content (typically less than 3% by weight).

Small, submerchantable[21] logs that do not meet sawlog or firewood specifications could also be recovered from timber harvest operations. In some cases, the larger logs (e.g., six-inch and larger diameter measured small end inside bark) command a higher value, which could leave the smaller logs available (e.g., under six-inch diameter) for value-added utilization. These smaller logs can be diverted to value-added uses such as posts or poles, firewood, or as raw material feedstock for animal bedding, compost, landscape cover, or fuel.

---

[19] Discussions with Novo Power plant manager confirm that pinyon-juniper makes up almost 25% of Novo's annual fuel supply.
[20] Per discussions with local timber harvest contractors.
[21] Submerchantable material = small stems, typically under 8" diameter at breast height, that are too small to be manufactured into merchantable forest products (e.g., lumber).

A primary market driver influencing active timber management for any given region is demand for sawlogs. Interviews with timber sale purchasers[22] active in the region (primarily on the Coconino NF and Kaibab NF) confirmed that sawlog markets are not well developed. However, there appears to be strong interest for new investment in expansion and upgrading of existing sawmills in the region.[23] The primary reason for additional investment in sawmill infrastructure is the expected ramp up of the 4FRI stewardship contract.

Currently there are four commercial sawmills within or tributary to the FSA, along with two firewood operations (purchasing firewood logs). All six operations procure roundwood (sawlogs and firewood logs) harvested within the FSA:

- Newpac Fibre, LLC sawmill at Williams
- Perkins Forest Products sawmill at Williams
- Lumberjack Timber, LLC sawmill at Heber
- Southwest Forest Products sawmill at Phoenix
- Canyon Wood firewood operation at Camp Verde
- High Desert Firewood operation at Winslow

Proximity to forest products manufacturing facilities is a major influence on sawlog and firewood log markets. Facilities located nearest to the NAU campus are the Newpac Fibre sawmill and Perkins Forest Products sawmill, both situated at Williams (about 34 miles from Flagstaff). The Lumberjack Timber, LLC facility at Heber is located about 134 miles from Flagstaff, but it is accessing some sawtimber from the FSA.

Additional sawmill capacity is likely as new or recently refurbished operations at Vaagen Brothers near Eagar and the White Mountain Apache Timber Company at Whiteriver enter commercial service. These facilities are not located tributary to the Flagstaff FSA (approximately 180 miles), but they will influence regional sawlog demand and generate forest products residuals.

Four Forest Restoration Initiative (4FRI)

As noted in Table 14, the forested landscape is managed by the Coconino NF and the Kaibab NF (67% and 24% of the forested landscape within the FSA respectively). Interviews with USFS staff[24] confirmed that approximately 95% of the timber harvest and restoration activities on these two forests are integrated into the 4FRI stewardship contract. Two other national forests, Tonto NF and the Apache-Sitgreaves NF, are also included in the 4FRI project but are located outside of the FSA.

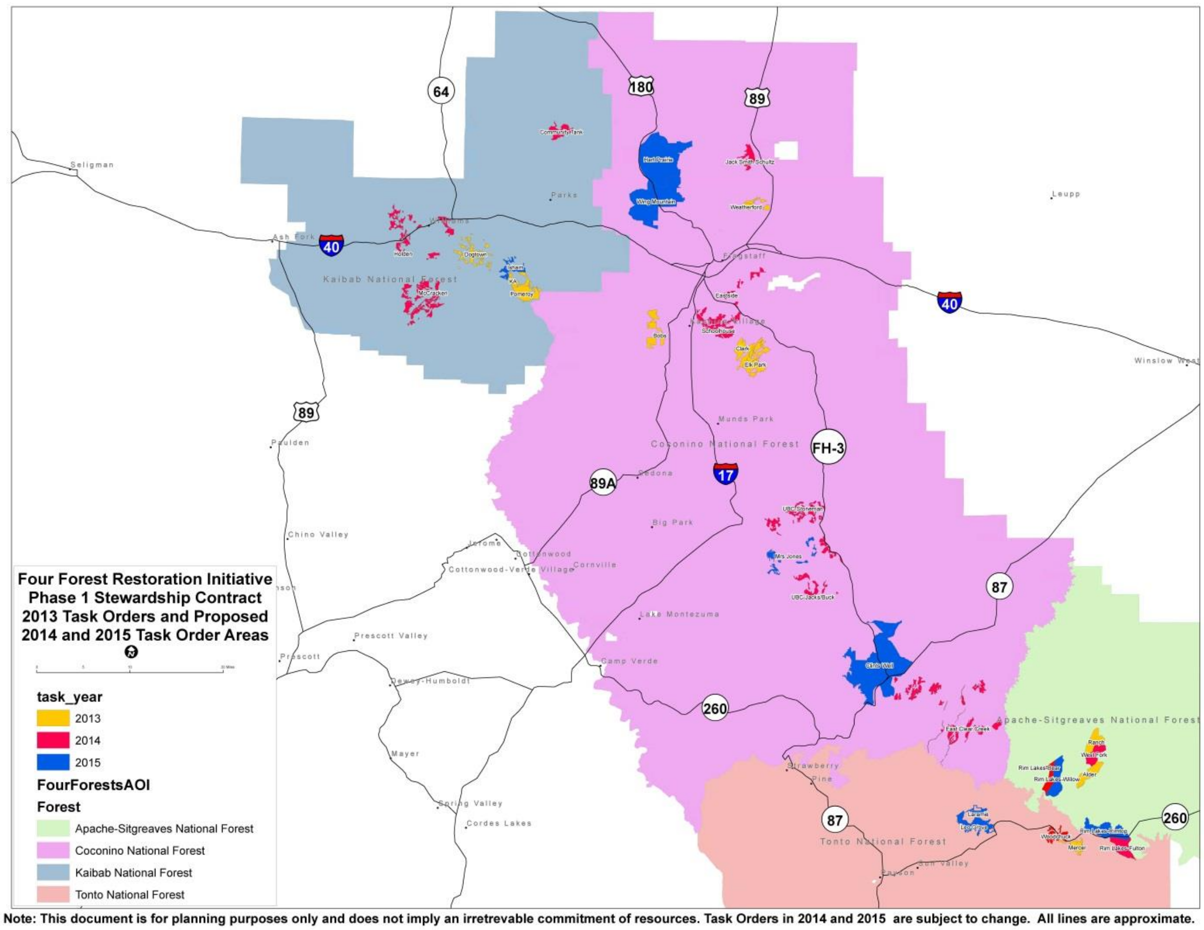
The contractor now selected to implement 4FRI is Good Earth Power. 4FRI was initially awarded to Pioneer Forest Products, but Pioneer was not able to secure capital financing for a planned forest products manufacturing facility at Winslow, Arizona. Pioneer transferred the

[22] High Desert Investments, Perkins Timber Harvesting, Newpac Fibre, LLC, and Good Earth Power.
[23] Discussions with Perkins Timber Harvesting, Newpac Fibre, LLC, and Good Earth Power.
[24] Dick Fleishman, Coconino NF; Kim Newbauer, Coconino NF; and Jack Hillskotter, Kaibab NF.

4FRI contract to Good Earth Power in September 2013 (with USFS concurrence). Discussions with Good Earth Power representatives[25] confirmed a strong interest to cooperate with NAU to provide forest biomass material for a potential bioenergy facility on campus.

The primary goal of the 4FRI effort is to treat targeted landscapes to address fuels reduction, forest health, and wildlife/plant diversity. A key objective is to maintain and enhance sustainable ecosystems in the long term. A total of 300,000 acres of forest landscapes (primarily ponderosa pine cover type) are targeted for treatment by 2022. Task orders have been issued by the USFS for treatment of about 15,000 acres within the 4FRI project area so far. Plans are to issue task orders for about 26,000 acres in fiscal year 2014, with an increase to about 30,000 to 33,000 acres per year in fiscal years 2015 through 2021. Figure 20 shows the task orders and targeted treatment areas for 2013 through 2015.

Figure 20. 4FRI Task Orders, 2013 through 2015[26]



Note: This document is for planning purposes only and does not imply an irretrevable commitment of resources. Task Orders in 2014 and 2015 are subject to change. All lines are approximate.

Flagstaff Watershed Protection Project

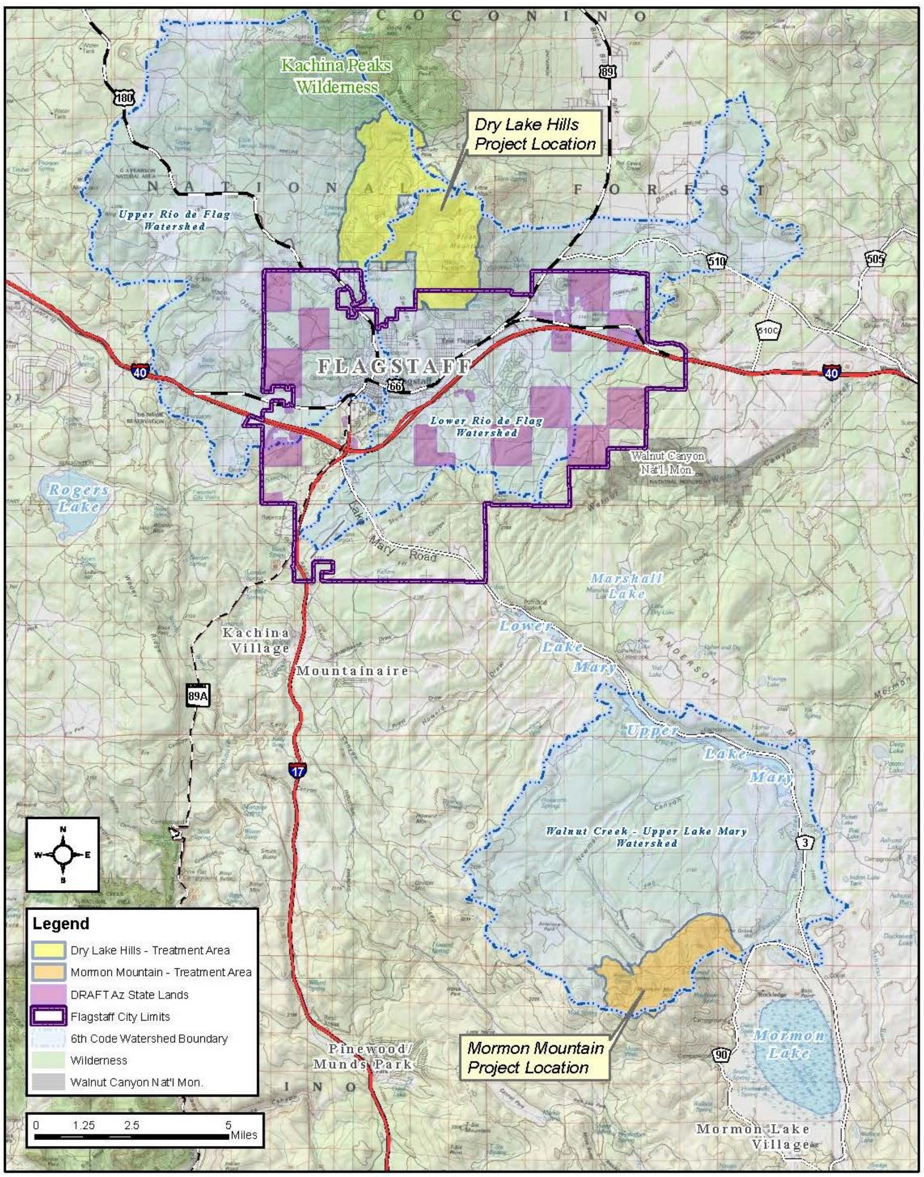
In addition to activities associated with 4FRI, the USFS is also working in partnership with the City of Flagstaff, Coconino County, and Arizona Division of Forestry in support of the Flagstaff

[25] Jason Rosamond, CEO and Peter McNulty, Water Resources Director.
[26] 4FRI task order map is provided by the USFS.

Watershed Protection Project (FWPP). In November 2012, the residents of Flagstaff voted in favor of a $10 million bond to support forest restoration efforts within strategic watersheds located on the Coconino NF and on State of Arizona lands. The FWPP is one of several examples in the U.S. where municipalities are investing in targeted watersheds managed by public agencies (like the USFS and Arizona Division of Forestry). A primary concern is the impact of catastrophic wildfire on domestic watersheds that serve municipalities (like Flagstaff).

The FWPP is targeting fuels treatment and forest restoration work on approximately 10,000 to 14,000 acres by 2020. Areas that will receive treatment include the Upper and Lower Rio de Flag watersheds and the Walnut Creek-Upper Lake Mary watershed. Figure 21 shows the location of these watersheds.

Figure 21. FWPP Proposed Treatment Areas[27]



[27] Excerpted from the FWPP Implementation Plan.

The Coconino NF has signed a Memorandum of Understanding with the City of Flagstaff to prepare plans to implement the FWPP. Once approved, the implementation plans will be managed by the Coconino NF (on USFS managed land) and the Arizona Division of Forestry (on state trust lands). At this time, approximately 1,400 acres have been approved through the National Environmental Policy Act (NEPA) planning process for treatment. During 2012 and 2013, about 100 acres have been thinned using hand crews. All of the thinned material was piled and burned on site. Due to uncertain market conditions for small roundwood and biomass material and relatively steep slopes, the USFS is planning (in the short term) to continue to pile and burn thinned material generated during implementation of the FWPP. Much of the landscape included in the FWPP is challenging and will likely be treated using helicopters and cable yarding systems. Forest biomass recovery may be very limited due to high collection costs and forest road systems that may not support chip truck traffic.[28]

Discussions with Coconino NF staff[29] confirmed that the next steps for the FWPP would be offering the 900-acre Orion Timber Sale for bids in January 2014. TSS confirmed that the bid was released in January 2014 and that there were no acceptable bids for this timber sale. The sale is now in the process of being added to a 4FRI task order. The NEPA planning process is currently underway for the remaining 13,000 FWPP acres targeted for treatment. A Record of Decision is expected to be issued around November 2014 with treatment planned through 2020.

Arizona State Trust Lands

State trust lands make up about 2% of the forested landscape within the FSA. Discussions with Arizona State Division of Forestry staff[30] confirmed that forest management activities on state lands are very dependent upon grant funding (primarily federal funds) targeting fuels treatment or restoration. In addition, a major challenge is the relative lack of local markets for sawlogs or biomass material. In the past three years (2011 through 2013), between 350 and 450 acres have been treated per year. Many of these treatments were focused on restoration work targeting areas damaged by wind events (e.g., tornado) and by wildfires.

State Division of Forestry staff is forecasting that approximately 200 acres per year of commercial forest thinning and 100 acres per year of hand thinning are planned in the coming years.

Camp Navajo

The Arizona Army National Guard manages a heavily forested 28,500-acre parcel located due west of Flagstaff near Bellemont, Arizona. Known as Camp Navajo, this military reserve was established in 1942 as a military supply depot and multi-service training site. Prior to military use, the land was managed for homesteads, ranching, and timber. In 1942, privately held parcels were purchased and combined with federal land (Coconino NF and Kaibab NF) to form the Camp Navajo Ordnance Depot (now known as Camp Navajo).

[28] Per discussions with Erin Phelps, Project Manager, FWPP, Coconino NF.
[29] Ibid.
[30] Keith Pajkos, Forester, Arizona Division of Forestry.

Information provided by the Arizona Army National Guard natural resource manager[31] confirmed that Camp Navajo includes about 19,000 acres of forested area. Made up primarily of ponderosa pine type, the camp has recently updated its Integrated Natural Resources Plan. The plan is focused on forest treatment activities that will reduce the incidence of large catastrophic wildfires and restore forest resiliency and function consistent with the camp's military mission. In the near term, a three-phase treatment plan is scheduled for implementation:

- Phase I: 4,700 acres treated between 2015 and 2017;
- Phase II: 6,300 acres treated between 2017 and 2020; and
- Phase III: 3,850 acres treated between 2020 and 2023.

Assuming this three-phase plan is implemented, approximately 1,000 to 1,650 acres per year will be treated starting in 2015. The Camp Navajo resource manager confirmed that while all timber harvest residuals generated as a result of timber harvest and fuels treatment activities are currently piled and burned, there is a strong preference for collection, processing, and removal of this material.

Flagstaff Fire Department

The Flagstaff Fire Department is currently managing fuels treatment projects within the community of Flagstaff. Discussions with Flagstaff Fire Department staff[32] confirmed that the department is sponsoring fuels treatment projects strategically located within the wildland urban interface. Most of the material that is thinned is processed into personal use firewood, and the residuals (limbs and tops) are piled and burned on site. Some of this residual material could be collected and processed for use as feedstock.

Planned Forest Treatment for All Ownerships

Forest acreage planned for treatment has a major influence on the availability of sawlogs and timber harvest residuals in the FSA. Summarized in Table 15 are planned treatments by ownership within and tributary to the FSA commencing in 2015.

[31] Bruce Buttrey, Natural Resource Manager, Forester, Arizona Army National Guard.
[32] Paul Summerfelt, Flagstaff Fire Department.

Table 15. Forest Acreage Planned for Treatment within or Tributary to the FSA Commencing 2015

LAND OWNER/ LAND MANAGER	TREATMENTS PLANNED - LOW (ACRES/YEAR)	TREATMENTS PLANNED - HIGH (ACRES/YEAR)
Four Forest Restoration Initiative	15,000	30,000
Flagstaff Watershed Protection Project	1,000	2,000
Arizona Division of Forestry	100	200
Camp Navajo	1,000	1,650
Flagstaff Fire Department	100	200
TOTALS	**17,200**	**34,050**

Due to transport logistics (e.g., topography, road systems), some portions of the FSA are not economically or physically accessible for the recovery and transport of woody biomass material. Discussions with local foresters[33] and timber harvest contractors[34] confirmed that between 10% and 30% of the region has forest transportation systems (primarily forest roads managed by the USFS) that will allow log truck traffic but are not passable for chip truck traffic. For the purposes of this forest biomass feedstock review, TSS assumes 30% of the forest landscape and acres targeted for treatment are not conducive (or available) for biomass removal.

<u>Summary of Biomass from Forest Operations</u>

TSS's experience[35] with forest biomass material collection and processing confirms that a recovery factor of 1 green ton (GT)[36] per hundred cubic feet (CCF)[37] of merchantable timber harvested is consistent with the harvest of ponderosa pine stands within the FSA. The one GT per CCF assumes that an appropriate volume of down woody material is left on site to provide habitat for a variety of wildlife species and for soil nutrient cycling.

Interviews with timber harvest contractors and foresters[38] familiar with the 4FRI task orders and targeted acres for treatment revealed that an average of four to eight CCF per acre of merchantable[39] sawtimber will likely be removed as the 4FRI project is implemented. Assuming an average sawtimber removal volume of six CCF per acre, and a biomass recovery factor of one GT per CCF, approximately six GT per acre of limbs/tops are potentially available for

[33] Marlin Johnson, Good Earth Power.
[34] Ken Ribelin, High Desert Investment.
[35] Consistent with TSS 2002 preliminary feasibility assessment for a biomass power plant in northern Arizona
[36] GT = two thousand pounds of wood waste material not corrected for moisture content.
[37] CCF = hundred cubic feet.
[38] Ken Ribelin, High Desert Investment; Marlin Johnson, Good Earth Power; Erin Phelps, Forester, USFS.
[39] Merchantable material = sawtimber typically 10" and larger diameter at breast height that can be utilized as sawlogs for the manufacture into merchantable forest products (e.g., lumber).

processing into biomass feedstock. In addition, harvest contractors and foresters estimate that about six GT per acre of submerchantable material are also likely to be removed during harvest operations. [40] Table 16 summarizes forest biomass material potentially available by land owner/land manager.

Table 16. Forest Biomass Material Practically Available from Treatment Activities with, or Tributary to, the FSA Commencing 2015

LAND OWNER/ LAND MANAGER	TREATMENTS PLANNED PRACTICALLY[41] ACCESSIBLE (ACRES/YEAR)	RECOVERABLE FOREST BIOMASS (GT/ACRE)	TOTAL FOREST BIOMASS (GT/YEAR)
Four Forest Restoration Initiative	15,750	12	189,000
Flagstaff Watershed Protection Project	1,050	12	12,600
Arizona Division of Forestry	105	8	840
Camp Navajo	1,855	14	25,970
Flagstaff Fire Dept.	100	6	600
TOTALS	**18,860**		**229,010**

Forest Products Manufacturing

Forest products manufacturing residuals in the form of sawdust, bark, and chips represent a traditionally cost-effective source of high-quality feedstock. Generated as a manufacturing byproduct, this feedstock has relatively low processing costs and is typically produced year round. Currently there are very few commercial forest products manufacturing operations located within the FSA. The only facility in the region that appears to be in consistent operation is a small sawmill at Williams managed by Perkins Forest Products. Commercial operations commenced in April 2013 with daily lumber production of 4,000 to 8,000 board feet per day or about one million board feet per year.

Interviews with the owner[42] of Perkins Forest Products confirmed that approximately 15 GT of manufacturing residuals (primarily sawdust, bark, slabs) are generated daily. Some of this material is sold as firewood, landscape cover, and animal bedding. This material is potentially available as feedstock for a bioenergy facility at NAU. The total volume of residuals generated is about 3,000 GT per year.

Newpac Fibre, LLC, also located at Williams, is planning to install a commercial sawmill in the near term. Discussions with the CEO[43] confirmed plans to install a commercial sawmill in

---

[40] Ken Ribelin, High Desert Investment; Marlin Johnson, Good Earth Power; Erin Phelps, Forester, USFS.
[41] Adjusted with a 30% reduction due to forest access issues.
[42] Keith Perkins, Owner, Perkins Forest Products.
[43] Chris Stephans, CEO, Newpac Fibre, LLC.

Williams by mid 2014. Targeted scale of the sawmill complex at full build out (by 2015) is 50 million board feet of lumber per year. A sawlog storage area has been developed and Newpac Fibre should be receiving logs (primarily from 4FRI operations) by second quarter 2014. Plans are to break ground on the new sawmill complex by early April 2014. Estimates of manufacturing residuals generated on site by 2015 are 10,000 GT of sawdust, 40,000 GT of chips, and 10,000 GT of bark.

For the purpose of this biomass feedstock availability review, TSS finds that approximately 63,000 GT of forest manufacturing residuals are potentially available per year from sawmill facilities located within the FSA. As noted in the Current Competition section of this report (below), there are robust existing markets for sawmill residuals including landscape cover, animal bedding, and soil amendment. Assuming that one-half of this residual volume has higher value uses (e.g., soil amendment, landscape cover), the practically available biomass is estimated to be 31,500 GT per year.

Urban-Sourced Biomass

Tree service companies, local residents, and businesses in the greater Flagstaff area regularly generate wood waste in the form of tree trimmings, construction wood, and woody debris from residential/industrial demolition projects. Much of this wood waste is currently deposited at the Cinder Lake Landfill located just northeast of Flagstaff. The city of Flagstaff manages the Cinder Lake Landfill. Discussions with landfill staff[44] indicated that the landfill receives significant volumes of wood waste in the form of green waste (e.g., tree trimmings) and wood waste (e.g., construction wood). In 2012 (most recent data available), the total green waste received amounted to 406 GT and approximately 415 GT of wood waste, for a total of 821 GT. Historically, wood waste volume received at the landfill has been variable based on general economic conditions in the region. As the economy has rebounded and residential construction has increased, so too has wood waste volume delivered to the landfill.

Like many landfills, Cinder Lake Landfill is grinding green waste and wood waste on site and using this material as alternative daily cover. As the term implies, the processed woody material is used to cover the landfill with a layer between 6” and 12” to control odor and vermin. At this time, the Cinder Lake Landfill is in need of alternative daily cover material and does not have any excess woody material available as feedstock for a bioenergy facility.

Biomass Feedstock Competition Review

<u>Current Competition</u>

There are very limited existing markets for forest biomass and sawmill residuals generated within the FSA. Novo Power, located near Snowflake, is procuring forest biomass material composed of processed timber harvest residuals from forest operations located within economic transport distance. The plant manager[45] at Novo Power confirmed that due to the relatively high cost of transport, they are not procuring forest biomass material from operations on the Coconino

[44] Matt Morales, Senior Project Manager, Cinder Lake Landfill.
[45] Heath Hildebrand, Plant Manager, Novo Power.

National Forest or from sawmill operations in the greater Flagstaff region. Sawmill residuals[46] in Northern Arizona are currently sold as animal bedding, landscape cover, soil amendment, firewood, feedstock for power generation, or as feedstock for fuel pellets. The only operating sawmill within the FSA, Perkins Forest Products facility at Williams, is located some distance from existing biomass markets and currently has very limited markets for residuals.

Most of the excess forest biomass is being piled and burned on site, due to a lack of local markets located within economic haul distance of forest operations.

Potential Competition

TSS is not aware of any new forest biomass or sawmill residual processing or utilization facilities planned for locations within the FSA. Good Earth Power representatives have discussed the possibility of developing portable fuel pellet operations; however, this appears to be an early stage concept. For the purposes of this review, TSS assumes that there are no new facilities planned that might utilize woody biomass material generated within the FSA.

Biomass Feedstock Availability

Summarized in Table 17 are the results of biomass feedstock material availability analysis from forest operations, forest products manufacturing, and urban wood waste generated within the FSA. Note that the annual volume available forecast is presented in both GT and BDT.[47] Many commercial-scale bioenergy facilities operating in the West (including Novo Power) procure biomass feedstocks using BDT as the preferred unit of measure.

For bioenergy financing, a coverage ratio of 2:1 is typically preferred. Based on the findings in Table 17, there is sufficient coverage for an 8 MW power plant. For a 10 MW power plant, there is sufficient feedstock within the FSA to provide the coverage ratio of 1.7:1. To reach a 2:1 coverage ratio, feedstock supply outside of the 50-mile FSA would need to be considered.

Table 17. Biomass Feedstock Practically Available Annually from within the FSA, 2015

BIOMASS MATERIAL SOURCE	BIOMASS AVAILABILITY (GT/YEAR)	MOISTURE CONTENT (%)	BIOMASS AVAILABILITY (BDT/YEAR)
Forest Operations	229,010	50%	114,505
Forest Products Manufacturing	31,500	40%	18,900
Urban Wood Waste	0	25%	0
TOTALS	**260,510**		**133,405**

[46] Per discusions with Lumberjack Timber, LLC, Heber, Arizona.
[47] BDT = 2,000 pounds of wood waste at zero percent moisture content.

Costs to Collect, Process, and Transport Biomass Material

There are commercial-scale contractors equipped to collect, process, and transport forest biomass material operating within the FSA. TSS relied on discussions with forest biomass contractors operating in the region, in addition to TSS's past experience, to analyze these costs. Table 18 provides results of the cost review.

Table 18. Biomass Feedstock Collection, Processing, and Transportation Costs

BIOMASS MATERIAL SOURCE	LOW RANGE ($/BDT)	HIGH RANGE ($/BDT)
Forest Operations Residuals	$30	$60
Forest Products Manufacturing Residuals	$20	$30
Urban Wood Waste	$25	$30

Assumptions used to calculate range of costs summarized in Table 18:

- Service fees or cost share are available from public agencies to offset the cost of collection, processing, and transport of forest operations residuals;
- One-way transport averages 30 miles for forest biomass material;
- Forest biomass is collected and processed into truck (at the landing) for $30 to $33 per BDT;
- Haul costs are $105 per hour for walking floor chip truck trailer; and
- Forest biomass chips average 14 BDT per load.

Five-Year Biomass Feedstock Pricing Forecast

A bioenergy facility sited at NAU will likely utilize a range of woody biomass feedstocks. Due to the seasonal availability of forest biomass (spring breakup is typically February to March and forest access is limited), there will be times that other feedstocks such as sawmill residuals will be required to facilitate year-round operation of the bioenergy facility. TSS recommends that a blend of feedstocks be considered for this facility. Table 19 summarizes a feedstock blend that includes a diversified range of feedstocks.

Table 19. Biomass Feedstock Blend for a Bioenergy Facility at NAU

BIOMASS MATERIAL SOURCE	DELIVERED COST ($/BDT)	PERCENT OF TOTAL
Forest Operations Residuals	$30.00	60%
Forest Products Manufacturing Residuals	$25.00	40%
Urban Wood Waste	N/A	N/A
TOTALS		**100%**

Table 20 provides a five-year biomass feedstock pricing forecast for a bioenergy facility that utilizes biomass feedstock sourced from the FSA. The base price of $28 per BDT is calculated using the optimized feedstock blend and delivered prices shown in Table 19.

Table 20. Five-Year Feedstock Pricing Forecast, 2015 to 2019

	2015	2016	2017	2018	2019
Feedstock Price Delivered to NAU South Campus	$28.00	$28.42	$28.85	$29.28	$29.72

The feedstock price forecast presented in Table 20 is based on the following assumptions:

- Feedstock supply chain is fully developed with feedstock available from forest operations and sawmills operating at Williams;
- Diesel fuel prices remain near $4.25 per gallon through 2015, then escalate slightly;
- Labor rates remain stable through 2015, then escalate slightly; and
- Biomass feedstock prices escalate at 1.5% annual rate due to increased diesel fuel and labor costs from 2016 through 2019.

For the 10 MW project size, both feedstock from the forest operations and from forest product manufacturing will have to be brought from beyond the 50-mile FSA. An additional $10 per BDT incremental cost should be expected for the additional transportation costs (to secure feedstock from outside the FSA). Assuming 50% of the forest products manufacturing feedstock is available within the FSA and 80% of the feedstock from forest operations is sourced from within the FSA, the weighted baseline price of feedstock for the 10 MW project is $31.20 per BDT.

Findings

Potential biomass feedstocks available for use in a bioenergy facility located on or near the NAU campus are primarily made up of residuals from forest operations and forest products manufacturing. TSS found that approximately 260,510 GT (135,405 BDT) per year of biomass feedstock material is sustainably available from within the FSA commencing in 2015. Over 88% of this volume is made up of forest operations residuals. Urban wood waste in the region is fully utilized and not likely available as feedstock in the near term.

The forested regions of the FSA are predominantly managed by federal agencies, with over 93% of the fir and pine type landscapes under the jurisdiction of the USFS (Coconino NF, Kaibab NF and Prescott NF). Long-term, sustainable availability of feedstock is very dependent upon vegetation management activities carried out by the USFS.

Implementation of the 4FRI stewardship contract will play a major role in the long-term availability of forest biomass material and sawtimber for the region. Good Earth Power is the prime contractor tasked with completing 4FRI task orders as issued by the USFS. Good Earth Power has expressed a strong interest[48] in facilitating the availability of biomass material for use as feedstock in a potential bioenergy project at NAU. TSS recommends that NAU consider reaching out to Good Earth Power to initiate discussions regarding a long-term feedstock purchase and sale agreement.

[48] Discussions with Jason Rosamond, CEO, Good Earth Power.

BIOENERGY DEVELOPMENT AND TECHNOLOGY ANALYSIS

The traditional bioenergy models include biomass to heat, biomass to electricity, and biomass to combined heat and power. Recently, alternative methods for bioenergy conversion have received increased attention, including biomass to biomethane, biomass to torrefied wood fuel, biomass to biochemicals, and biomass to advanced biofuels (primarily for transportation). While NAU could provide a market for biomethane, biomass to biomethane production is challenging on a small scale. According to a recent presentation from Southern California Gas Company, biomethane production is expected to be viable for production at scales greater than 1,500 MSCF/day.[49] Over a one-year period, this production rate represents over 8.5 times the average annual NAU natural gas consumption. NAU does not provide a ready market for torrefied wood fuel, biochemicals, or advanced biofuels. However, NAU may want to monitor the rapidly expanding biochemical and advanced biofuels markets due to their location amidst a significant forest biomass resource and the potential to partner with a biochemical or biofuels manufacturer to provide a unique opportunity for student and university research.

This analysis will review the conversion of woody biomass to electricity and heat. Anaerobic digestion technologies will not be reviewed, as they use high moisture organic solids and non-woody feedstocks.

Based on the findings from the Energy Load Assessment, TSS focused the technology analysis on three scenarios:

- Project Scenario 1: Biomass to Heat – 20 MMBtu per hr
- Project Scenario 2: Biomass to Electricity – 2.5 MW
- Project Scenario 3: Biomass to Electricity – 10 MW

Project Scenario 1 provides NAU with a renewable means of displacing natural gas demand on the South Campus. Project Scenario 2 allows NAU to displace some electric use on campus and Project Scenario 3 offers the ability to provide all of NAU's electricity while utilizing some waste heat to offset natural gas consumption.

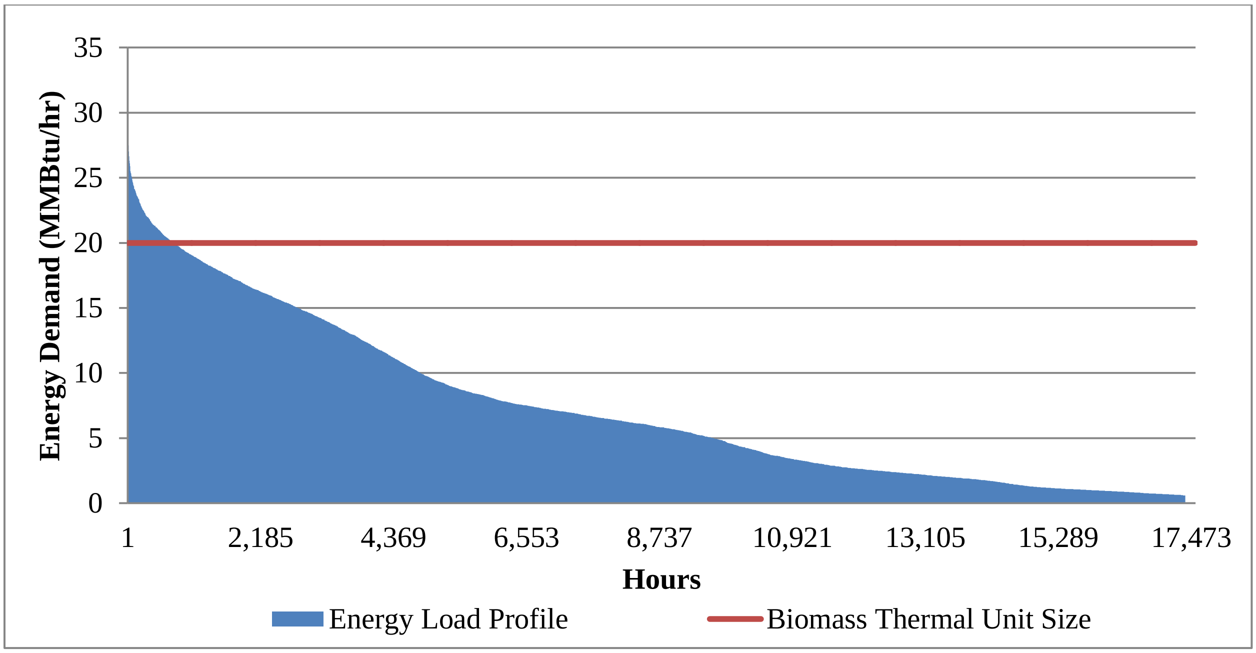
Project Scenario 1: Biomass to Heat

The conversion of biomass to heat is the most energy efficient conversion process of woody biomass. There are two mechanisms for this process: direct combustion and gasification. Direct combustion is the most traditional source of biomass heating. While gasification technology has been developed and used for several decades for the production of heat, electricity, and biofuels, the use of gasification for heating has been limited.

[49] Lucas, J. "CEC Staff Workshop on Challenges to Procuring Biomethane in California." May 31, 2013, Southern California Gas Company. http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-31_workshop/presentations/Jim-Lucas_Southern_California_Gas_Company.pdf

Biomass-to-heat technologies, when used to supplement fossil fuel consumption, are typically sized to optimize heat displacement and capacity factor. As a rule of thumb, sizing a unit to meet 70% to 80% of the projected peak load is appropriate to balance fuel displacement and capital cost (assumes an alternative source is available for peaking). This strategy also helps increase the applicability of biomass boilers by decreasing the output at the lowest turn-down ratio.[50] Based on the heat loads presented in Figure 5 in the Energy Load Assessment, the maximum annual peak load is projected to be 28.9 MMBtu/hr. At 70% of peak load, the biomass boiler sizing would be approximately 20 MMBtu/hr. By sizing for 70% of peak load, the capacity factor increases from 25.3% (at 100% of peak load) to 36.2% while still covering 98.7% of demand. Figure 22 shows the total potential output of the biomass thermal unit compared to the energy load profile for the South Campus Heating Facility.

Figure 22. Sizing a Biomass Thermal Unit



A biomass to heat project would likely replace the existing 1970 Cleaver-Brookes boiler in the South Campus Heating and Cooling Plant. There are two configurations that could be utilized effectively for this system:

- Configuration 1: Direct-Fired Biomass Boiler
- Configuration 2: Gasification to a Producer Gas & Natural Gas Boiler

For either configuration, the bioenergy system is expected to be integrated into the South Campus Heating and Cooling Plant, which will require some additional modifications to accept wood chip deliveries and to accommodate the associated truck traffic.

Project Scenario 1 is expected to consume 5,317 BDT annually based.

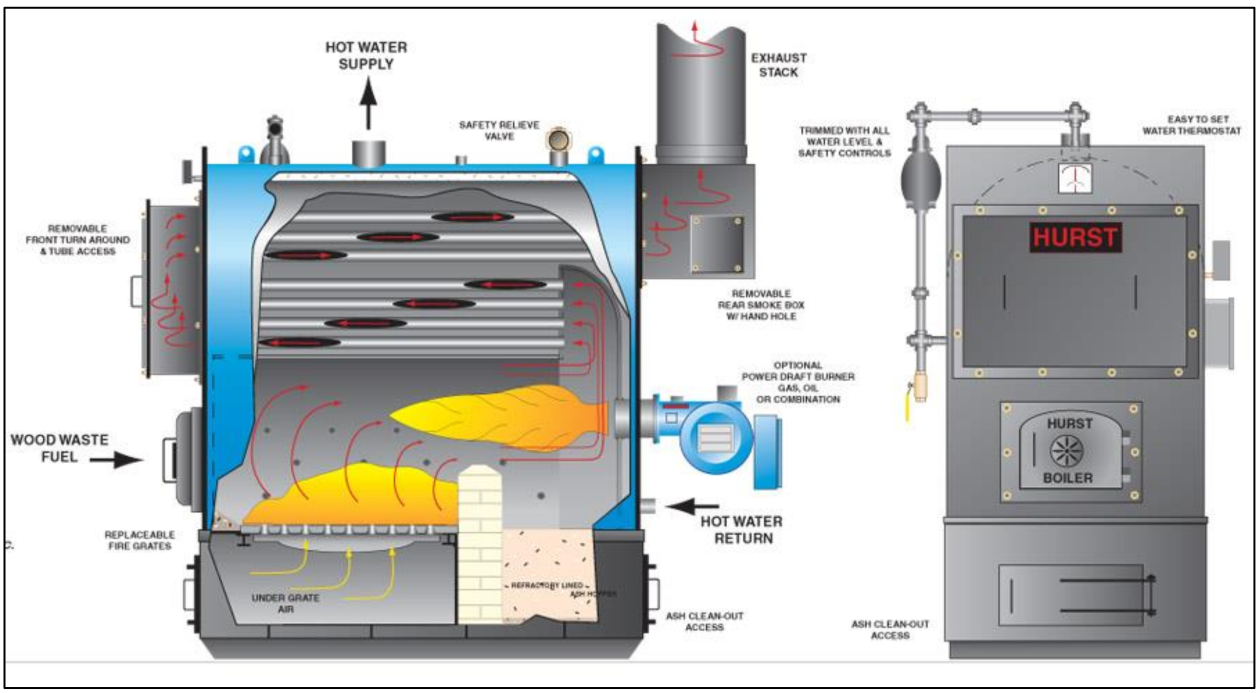
[50] Turndown ratio is a relative measure of a boiler's ability to scale back operation. For example, if the boiler heat output is turned down to 50% of its maximum, this would be a turndown ration of 2:1.

Configuration 1: Direct Combustion

Direct combustion is also referred to as a biomass boiler. Through the direct-combustion process, biomass is combusted in a biomass boiler system to produce hot water or steam.[51] Biomass direct combustion is the most common commercial-scale utilization of woody biomass for energy. A biomass boiler system would generate hot water that would be directly integrated into the existing system that feeds the south campus. The integration is expected to be identical to that currently used to integrate the existing hot water natural gas boilers.

After wood chips are delivered to the site, an automated system would convey the wood chips from the feedstock storage area to the biomass boiler where the feedstock would be directly combusted to provide heat to the boiler. The existing control systems used to monitor and operate the three boilers currently housed at the South Campus Heating and Cooling Facility are expected to be adequate for integration with a new biomass boiler system. A schematic of a biomass boiler is shown in Figure 23.

Figure 23. Schematic of a Biomass Boiler



Source: Hurst Boilers

Boiler size varies significantly by technology manufacturer; however, biomass boilers are typically larger than a comparably-rated natural gas boiler because the combustion chamber must be larger to process solid wood fuel.

Select biomass direct combustion manufacturers that produce biomass thermal units in the targeted heat output range are shown in Table 21. TSS utilized two coarse filters to identify

[51] For the purposes of this report, TSS considers technologies that have a gasification stage but do not capture the producer gas for use external to the process as direct combustion technology.

project developers: equipment size and developer experience. All firms identified in Table 21 have proven experience installing comparable biomass boiler systems utilizing chipped wood.

Table 21. Select Direct Combustion Boiler Manufacturers[52]

VENDOR	HEADQUARTERS	UNIT SIZES
Ameresco www.ameresco.com	Tempe, AZ	Technology Agnostic Developer[53]
Advanced Recycling Equipment www.advancedrecyclingequip.com	St. Mary's, PA	0.5-34 MMBtu/hr
Alternative Energy Solutions International (UniConfort) www.aesintl.net	Wichita, KS	0.3-20 MMBtu/hr
AFS Energy Systems www.afsenergy.com	Harrisburg, PA	1.2-40 MMBtu/hr
Chiptec www.chiptec.com	Williston, VT	1.5-60 MMBtu/hr
Ebnervyncke www.ebnervyncke.com	Wadsworth, OH	3.3-27 MMBtu/hr
Hurst www.hurstboiler.com	Coolidge, GA	1.2-60 MMBtu/hr
Messersmith www.burnchips.com	Bark River, MI	2-20 MMBtu/hr
SolaGen www.solageninc.info	St. Helens, OR	0.5-200 MMBtu/hr

Configuration 2: Gasification

Biomass gasification has been used to convert woody biomass to a producer gas since the early 1900s. While gasification is not utilized on a large scale throughout the U.S., gasification technology has been gaining momentum due to the potential for lower emissions rates and the potential to mix with and supplement natural gas streams.

Gasification is the production of gas from a low-oxygen, high-temperature environment that breaks down the feedstock to basic gaseous constituents (primarily hydrogen, carbon monoxide, methane, and carbon dioxide), leaving a biochar residue containing predominantly fixed carbon. Depending on the feedstock and the specific technology, the producer gas typically contains 1/5th to 1/6th the energy content of natural gas (per unit basis). The producer gas is captured and may be directly combusted to produce heat to provide hot water or steam or may be mixed with natural gas before combustion.[54]

[52] Some vendors describe their technology as gasification. TSS defines gasification technology as a technology that can collect, condition, and utilize the producer gas.
[53] A technology agnostic developer does not develop a specific technology and will use an RFP process along with their professional experience to select a technology vendor for the specific application.
[54] The technical definition of gasification is the low-oxygen thermal breakdown of feedstock; however, for the purposes of this report, TSS considers gasification technology as a system that employs gasification to create and capture producer gas.

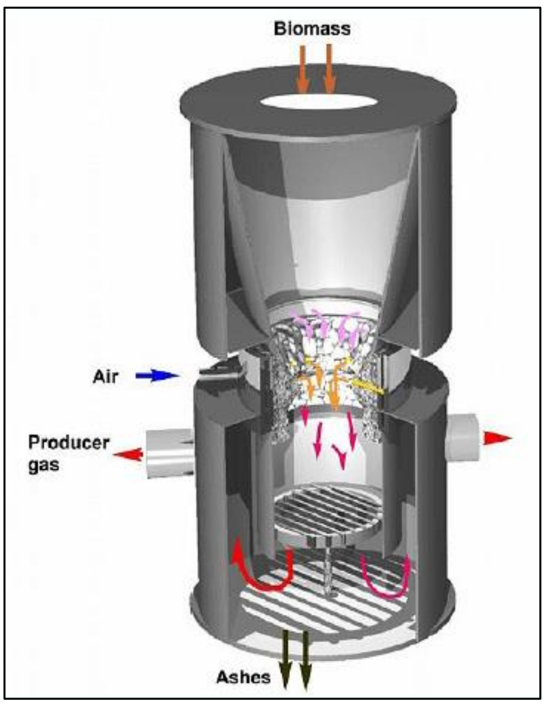
Producer gas from gasification is primarily composed of hydrogen, carbon monoxide, carbon dioxide, and methane (see Table 22). The ability for NAU's existing natural gas boilers to utilize producer gas should be discussed with the boiler manufacturers (e.g., Cleaver Brooks, Erie City Iron Works).

Table 22. Representative Producer Gas Composition

CONSTITUENTS	COMPOSITION
Hydrogen (H_2)	10-20%
Carbon Monoxide (CO)	15-25%
Carbon Dioxide (CO_2)	5-15%
Methane (CH_4)	0-15%
Nitrogen	45-55%

A gasification system would include a boiler capable of accepting a range of gas feedstock including 100% producer gas to 100% natural gas. This producer gas and natural gas boiler would allow the South Campus Heating and Cooling Plant to utilize as much renewable fuel as possible while still retaining the ability to co-fire or completely fire with natural gas. The flexible fuel boiler would be integrated into the existing system just as the existing natural gas boilers are currently integrated. A schematic of a gasifier is shown in Figure 24.

Figure 24. Schematic of a Gasifier



Source: Biomass Technology Group

This configuration provides for additional fuel flexibility, better ability to load follow, and a higher turndown ratio than with direct combustion technology. However, this configuration would require more space, as the boiler and the gasifier equipment require a larger footprint than the direct combustion unit. Gasification technology typically can require no water, as the process recovers water from the feedstock and air cooled chillers can be used for cooling the engine-generator. Also, gasification technology developers traditionally have less experience than direct combustion developers due to the maturity of the respective industries, and gasification technology is more sensitive to the moisture content of the feedstock.

While gasification technology has been studied and has been in commercial production for decades, commercial gasification technology is relatively new to the U.S. market. Table 23 identifies gasification developers that utilize gasification technology in thermal applications. TSS filtered developers by equipment size for Table 23. PHG Energy is the only developer with a gasification system strictly for thermal applications in the United States at this time.

Table 23. Select Gasification Developers for Thermal Applications

VENDOR	HEADQUARTERS	UNIT SIZES
BioGen www.biogendr.com	Santo Domingo, Dominican Republic	10-15 MMBtu/hr
PHG Energy www.phgenergy.com	Antioch, TN	20-25 MMBtu/hr
Phoenix Biomass Energy (Ankur Technology) www.phoenixenergy.net	San Francisco, CA	0.005-22 MMBtu/hr
Radian Bioenergy www.radianbioenergy.com	Salt Lake City, UT	10-40 MMBtu/hr

Project Scenario 2: Small-Scale Biomass to Electricity

A small-scale biomass to electricity project would displace electricity from the north campus meter. As identified in the Energy Load Analysis, a 2.5 MW project is expected to reduce the baseload north campus electricity demand while providing sufficient demand such that this meter remains within the requirements of the current rate schedule (more information in the Economic Analysis section). At this scale, the biomass project is estimated to consume 18,615 BDT per year.

At this scale, gasification processes are the most cost-effective configurations due to the high efficiency of an internal combustion engine generator compared to a steam turbine. In this configuration, the same gasification technology discussed for the thermal-only application generates the producer gas. The producer gas would be sent through a conditioning system to remove the tars and water components to produce syngas. The conditioning of the producer gas is necessary for applications that use internal combustion engines to create a refined syngas that can be better used by an internal combustion engine. Alternatively, the producer gas can be directly burned to provide heat to an organic rankine cycle turbine; however, the efficiency of this turbine is significantly less than an internal combustion engine (this can be challenging for small-scale gasification systems).

Waste heat is primarily generated from the engine's exhaust gas and from the engine's jacket water. Much of the waste heat will be used to dry incoming forest-sourced feedstock as gasification technology requires moisture contents from 10 to 15 percent (incoming feedstock is expected to have 40 to 50 percent moisture contents). Heat that is not used for feedstock drying is available from the engine and would account for approximately 3.5 to 4 MMBtu/hr of heat.[55] For most engine types, the engine jacket water ranges from 120°F and 160°F.[56] This low temperature heat is expected to be too low for utilization at the South Campus Heating and Cooling plant.

The electricity would be generated on site and a direct, dedicated line would transport the electricity from the project site to the APS substation. Alternative interconnection options should be discussed with APS to determine appropriate metering options and to maintain the stability of the campus electric grid.

Table 24 identifies a select group of technology developers with experience using gasification systems to produce electricity in the 2 MW to 3 MW range.

Table 24. Select Developers for Small-Scale Gasification Systems

VENDOR	HEADQUARTERS	COMPANY TYPE
BioGen www.biogendr.com	Santo Domingo, Dominican Republic	Vendor and Developer
Nexterra www.nexterra.ca	Vancouver, BC	Vendor and Developer
PHG Energy www.phgenergy.com	Antioch, TN	Vendor and Developer
Phoenix Biomass Energy (Ankur Technology) www.phoenixenergy.net	San Francisco, CA	Vendor and Developer
Radian Bioenergy www.radianbioenergy.com	Salt Lake City, UT	Vendor and Developer
Zero Point Energy www.zeropointcleantech.com	Potsdam, NY	Vendor and Developer

Project Scenario 3: Large-Scale Biomass to Electricity

A large-scale biomass to electricity project would generate power to serve all of campus load. As identified in the Energy Load Assessment, a 10 MW project is expected to be of sufficient size to meet the campus electrical load throughout the year. With a large-scale biomass to electricity project, the NAU campus would remain connected to the APS grid to provide stability and backup power. At this scale, the biomass project is estimated to consume 74,460 BDT per year.

At this scale, direct combustion configurations are typically more cost effective based on the limited scalability of small-scale gasification plants.[57] Direct combustion applications typically use the thermal energy generated by the combustion of biomass to heat a working fluid, typically high-pressure steam, to drive a turbine. Steam turbines and organic rankine cycle systems both utilize this process.

[55] Vendor specifications.
[56] Vendor specifications.
[57] Bain, R., "Biomass Gasification: USDA Thermochemical Conversion Workshop," National Renewable Energy Laboratory. September 2006.

The electricity would be generated on site and a direct, dedicated line would transport the electricity from the project site to the APS substation. Alternative interconnection options should be discussed with APS to determine appropriate metering options and to maintain the stability of the campus electric grid.

Waste heat would be used to provide heat for the South Campus Heating and Cooling Facility. A 10 MW facility may provide up to 30 MMBtu per hour of waste heat.[58]

Table 25 identifies a select group of developers with experience developing large-scale biomass-to-electricity applications.

Table 25. Select Developers for Large-Scale CHP Applications

VENDOR	HEADQUARTERS	COMPANY TYPE
Ameresco www.ameresco.com	Tempe, AZ	Technology Agnostic Developer
Cambridge Entech www.cambridgeentech.com	Cambridge, MD	Technology Agnostic Developer
Chiptec www.chiptec.com	Williston, VT	Vendor and Developer
Ebnervyncke www.ebnervyncke.com	Wadsworth, OH	Vendor and Developer
Hurst www.hurstboiler.com	Coolidge, GA	Vendor and Developer
McKinstry www.mckinstry.com	Irvine, CA	Technology Agnostic Developer
Precision Energy Services www.pes-world.com	Hayden, ID	Technology Agnostic Developer

Project Location and Infrastructure

TSS reviewed potential sites for bioenergy project development and has identified preferred locations for each of the project scenarios (Figure 25). Project Scenario 1 would be located at the South Campus Heating and Cooling Plant to minimize infrastructure. While space constraints are certainly a concern for this site, TSS's preliminary assessment indicates that there is potential for a biomass-to-heat project dependent on the project size and manufacturer.

For Project Scenario 2 and Project Scenario 3, the area south of the substation (south of the Project 1 site) was considered for project siting; however, the constraints identified from the existing solar photovoltaic array, the water projects, and the utility line easements precluded the area from a preferred project location. The site indicated in Figure 25, east of Lone Tree Road, balances accessibility, space, proximity to loads, and minimizes impacts on limited campus space.

[58] U.S. EPA Combined Heat and Power Partnership. "Catalog of CHP Technologies." December, 2008. http://www.epa.gov/chp/documents/catalog_chptech_full.pdf

For any of the three project scenarios, biomass is expected to be delivered on an as-needed basis, thereby minimizing the amount of onsite storage. While there are seasonal constraints for feedstock delivery from the forest, the blend of forest-sourced materials and sawmill residuals should allow for as-needed delivery. Space for storage will be most constrained for Project Scenario 1 which has significant physical limitations based on the surrounding infrastructure.

Figure 25. Potential Project Site Selection

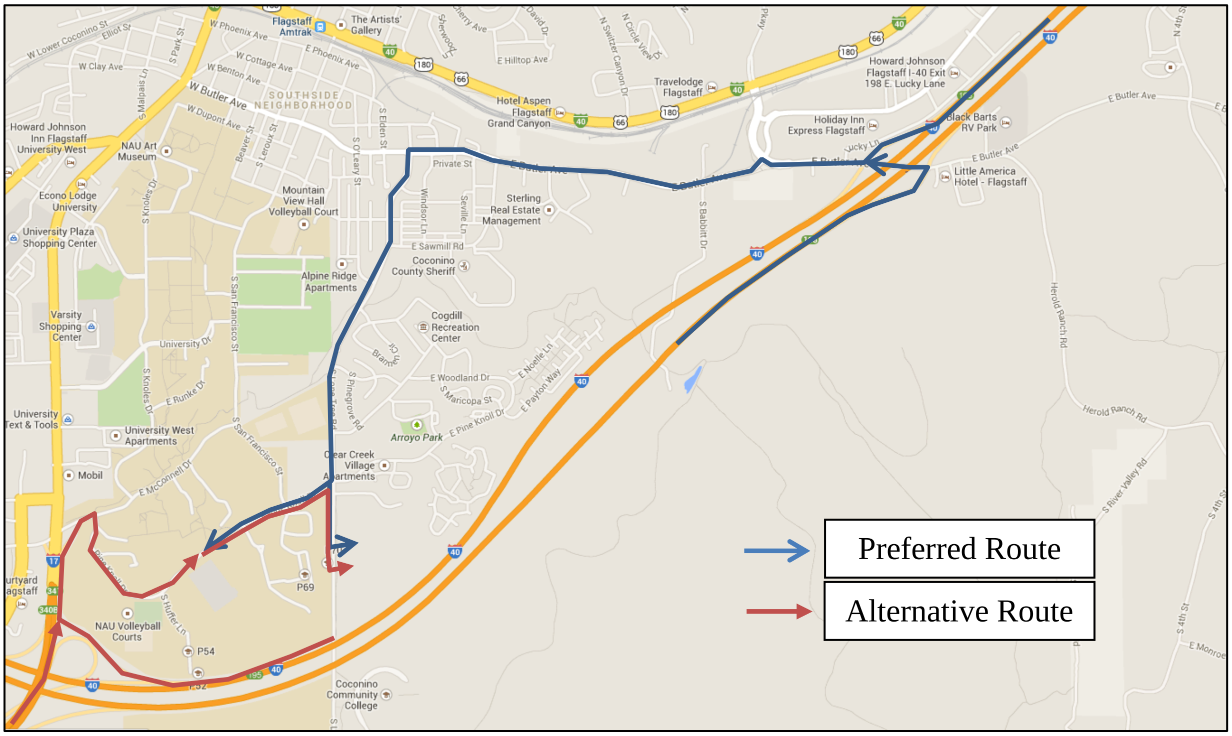
Source: Google Maps

A biomass facility will require feedstock delivery on a consistent basis to minimize the need for wood chip storage. As described in the Biomass Resource Availability Review, wood is delivered via a chip van (a tractor trailer designed specifically for wood chips). Chip vans typically have a 25-ton capacity. Since forest-sourced biomass usually has approximately 45% moisture, the effective loading capacity is 14 BDT. The feedstock demands for the different project scenarios are shown below.

- Project Scenario 1: Biomass to Heat – 40.4 BDT/day (5,317 BDT/year) = 3 truckloads per day;
- Project Scenario 2: Small-Scale Biomass to Electricity – 60 BDT/day (18,615 BDT/year) = 4 truckloads per day; and
- Project Scenario 3: Large-Scale Biomass to Electricity – 240 BDT/day (74,460 BDT/year) = 16 truckloads per day.

Truck traffic may vary daily and some level of onsite storage is expected to allow flexibility for deliveries. Due to the potential for high traffic volumes, TSS reviewed access to the preferred sites. The preferred route for truck traffic, shown in blue in Figure 26, is via Lone Tree Road from Butler Avenue to avoid congestion and increasing traffic noise through campus. The alternative and most direct route, shown in red in Figure 26, is via Pine Knoll Drive from McConnell Drive. This traffic pattern can serve all proposed project sites. Deliveries are expected to be scheduled during the day to avoid early morning noise near the residences.

Figure 26. Traffic Patterns: Biomass to Heat Project



Campus Biomass Power

Several college campuses currently employ biomass technology to provide onsite heat and/or power. A select group of colleges that utilize biomass are listed below:

- Bennington College (Bennington, VT): Reduce fuel oil consumption
- Chadron State College (Chadron, NE): Reduce natural gas consumption
- Colby College (Waterville, ME): Reduce fuel oil consumption
- Colorado State University Foothills Campus (Fort Collins, CO): Reduce natural gas consumption
- Ferrum College (Ferrum, VA): Reduce fuel oil consumption
- Green Mountain College (Poultney, VT): Reduce fuel oil consumption
- Middlebury College (Middlebury, VT): Reduce fuel oil consumption
- Mount Wachusett Community College (Gardner, MA): Reduce electricity demand for electric boilers
- Nova Scotia Agricultural College (Truro, Nova Scotia): Reduce fuel oil consumption
- University of Idaho (Moscow, ID): Reduce natural gas consumption
- University of Iowa (Iowa City, IA): Meet renewable energy and carbon reduction goals
- University of Missouri (Columbia, MO): Converted coal to biomass

Findings

For biomass-to-heat applications, the direct combustion market is significantly more robust and has more development experience than the gasification industry. However, gasification technologies may provide additional flexibility to integrate into the existing infrastructure and to provide redundancy. One of the largest constraints to biomass-to-heat development will be the limited space available at the South Campus Heating and Cooling Facility.

Small-scale biomass-to-electricity applications are best suited for gasification technology, and the gasification industry has greater experience in biomass-to-electricity applications than for heat only. Large-scale biomass-to-electricity applications can utilize both gasification and direct combustion technologies; however, for NAU's heat utilization system, a direct combustion configuration may provide advantages for heat utilization. Based on the selected site, the transportation of waste heat for value-added utilization will be more economical for large-scale projects and may have limited applicability due to the potential for low heat volumes and low temperature heat from a gasification system.

AIR EMISSIONS IMPACT ANALYSIS

Literature Search

TSS performed a literature search to better understand the life-cycle air emissions implications of bioenergy development. In addition to published literature and for consistency, TSS utilizes EPA AP-42 for emissions when appropriate. Relevant literature includes the following.

- Lee, C., Erickson, P., Lazarus, M., Smith, G., 2010. Greenhouse Gas and Air Pollutant Emissions of Alternatives for Woody Biomass Residues. *Stockholm Environmental* Institute, November 2010.
  - This study estimates the GHG emissions associated with 15 fates including on-site decomposition, on-site combustion, chipping for mulch, integrated gasification and combustion, and cogeneration. The findings from the analysis support the notion that bioenergy facilities reduce the total GHG emissions profile.
- Springsteen, B., Christofk, T., Eubanks, S., Mason, T., Clavin, C., Storey, B. Emission Reductions from Woody Biomass Waste for Energy as an Alternative to Open Burning. *Journal of the Air & Waste Management Association*, *61(1), 63-68*. 2011.
  - This study discusses the air emissions implications of alternative uses for biomass energy. This study shows emissions decreases in criteria pollutants and GHG through biomass utilization in energy projects.
- Mann, M., Whitaker, M., Driver, T. Life Cycle Assessment of Existing and Emerging Distributed Generation Technologies in California. National Renewable Energy Laboratory. 2011.
  - This study reviews the reduction potential for many renewable and non-renewable energy systems with regards to criteria pollutants and GHG. This study indicates that bioenergy utilization will contribute to the overall emissions reductions.
- Mann, M., Spath,, P. A Life Cycle Assessment of Biomass Cofiring in a Coal-Fired Power Plant. *Clean Products and Processes, 3*(2), 81-91. 2001.
  - This study is focused on biomass cofiring and not distributed generation; however, there is a detailed analysis of GHG emissions from alternative fates for biomass. Findings indicate that there are benefits of CO_2 and CH_4 emissions.
- Stephens, S., Moghaddas, J., Hartsough, B., Moghaddas, E., Clinton, N. Fuel Treatment Effects on Stand-Level Carbon Pools, Treatment-Related Emissions, and Fire Risk in a Sierra Nevada Mixed-Conifer Forest. *Canadian Journal of Forest Research 39.8: 1538-1547*. 2009.
  - This study reviews the carbon sequestration benefits of forest management techniques. This study identifies fire return interval as a defining assumption necessary to understand if there are any CO_2 sequestration benefits.

- Saah, D., Robards, T., Moody, T., O'Neil-Dunne, J., Moritz, M., Hurteau, M., Moghaddas, J. Developing an Analytical Framework for Quantifying Greenhouse Gas Emissions Reductions from Forest Fuel Treatment Project in Placer County, California. 2012.
    - This study finds that carbon sequestration potential is largely due to fire return intervals. The findings of this paper, focused specifically in the Sierra region in Northern California, indicate that forest management programs are beneficial for areas with a fire return interval of less than 15 years.
- Winford, E., Gaither, J. Carbon Outcomes from Fuels Treatment and Bioenergy Production in a Sierra Nevada Forest. *Forest Ecology and Management, 282, 1-9*. 2012.
    - This study focuses carbon sequestration potential based on forest management programs. This study, focused on the Sierra Nevada forests, identified that forest management is beneficial in areas with fire return intervals less than 31 years.
- Morris, G. The Value of the Benefits of U.S. Biomass Power. *National Renewable Energy Laboratory*. Contract Number DE-AC36-99-GO10337. November 1999.
    - This study reviews emissions from alternative fates of woody biomass including open burning, landfill, composting, spreading/mastication, and forest accumulation.
- Finkral, A., Evans, A. The Effects of a Thinning Treatment on Carbon Stocks in a Northern Arizona Ponderosa Pine Forest. *Forest Ecology and Management. 255, 2743-2750*. 2008.
    - This study reviews the carbon storage potential from forest thinning practices that vary predominantly by forest residue end-products. With pile and burn practices, the forest thinning practices release carbon emissions while the utilization of forest thinning residue in pallets and construction will result in net carbon storage.
- Huang, C., Asner, G., Martin, R., Barger, N., Neff, J. Multiscale Analysis of Tree Cover and Aboveground Carbon Stocks in Pinyon-Juniper Woodlands. *Ecological Applications, 19(3) 668-681*. 2009.
    - This study reviews the aboveground carbon storage potential from pinyon-juniper forests indicating an average of 5.2 Mg C per hector for pinyon-juniper landscapes.
- Hurteau, M., Stoddard, M., Fule, P. The Carbon Costs of Mitigating High-Severity Wildfire in Southwestern Ponderosa Pine. *Global Change Biology, 17, 1516-1521*. 2011.
    - This study reveals that while the carbon stock per unit area from fire exclusion may be higher than in managed forests, the carbon storage in these forests is unsustainable, particularly given the potential for high-severity wildfire and the potential for vegetation type conversion in western ponderosa pine forests.
- Roccaforte, J., Fule, P., Chancellor, W., Laughlin, D. Woody Debris and Tree Regeneration Dynamics following Severe Wildfires in Arizona Ponderosa Pine Forests. *NRC Research Press*. 2011.
    - This study focuses on the overstory and regeneration in Arizona's ponderosa pine forests revealing that at over half of the studied sites, ponderosa pine overstory and regeneration were completely lacking, yielding shrublands or grasslands rather than a return to ponderosa forests.

- Savage, M., Mast, Joy. How Resilient are Southwestern Ponderosa Pine Forests after Crown Fires. *Canadian Journal of Forest Research*, 35, 967-977. 2005.
  - This study identifies two predominant trends after severe wildfires in ponderosa pine forests across Arizona and New Mexico: 1) a robust recovery to ponderosa pine and 2) a deflection of forest recovery towards another vegetation state.

Air Emissions Lifecycle Methodology

TSS utilized a lifecycle approach to evaluate the potential criteria pollutant impacts of bioenergy projects. Air emissions from bioenergy projects are traditionally higher than those of comparable natural gas projects due to the relative inefficiencies of solid fuel combustion; however, emissions offsets from the diverted feedstock may significantly reduce the air emissions impacts depending on the feedstock blend. TSS also evaluated greenhouse gases using the Clean Air-Cool Planet Campus Carbon Calculator, the carbon calculator used by NAU.[59]

The benefits of biomass utilization are derived from the air emissions savings from the avoided alternative fate of the biomass. Focusing feedstock procurement on biomass that would otherwise be piled and burned provides the greatest regional air quality benefits. Per the Biomass Resource Availability Review, the majority of the forest-sourced feedstock will come from 4FRI. Under 4FRI, pile and burn will be only occasionally used; therefore TSS assumes that only 10% of the forest-sourced feedstock will come from other managements (e.g., Camp Navajo, State of Arizona, Flagstaff Fire Department) where pile and burn activity is a standard practice. This analysis does not account for biogenic carbon uptake. No carbon reduction is attributed from forest-sourced feedstock coming from 4FRI or from feedstock coming from forest products manufacturing.

TSS included the air emissions of biomass procurement and transportation, as this issue has gained attention as a potential challenge with biomass utilization. To be consistent, natural gas procurement and transportation (via pipeline) has been included. Where possible, TSS utilized emissions pathways within the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET) developed by Argonne National Laboratory for the life cycle analysis. However, the GREET model does not have a verified pathway for forest biomass electricity, heat production, or for forest biomass procurement; therefore, TSS relied on alternative studies for additional information.

The sources of emission factors are identified throughout the analysis with footnotes. Additional assumptions include:

- Biomass Boiler Efficiency: 70% (see the Energy Load Assessment);
- Natural Gas Efficiency: 80% (see the Energy Load Assessment);
- Biomass Thermal-Only Project sized at 20 MMBtu/hr operating with a 36.2% capacity factor (see the Energy Load Assessment); and
- Biomass combined heat and power (CHP) Project sized at 2.5 MW (with 4 MMBtu per hour of waste heat) and 10 MW (with 30 MMBtu per hour of waste heat) operating at

[59] Per direction from the NAU project team

either 85% capacity factor due to operational constraints or lower based on electricity demand (see the Energy Load Assessment).

The quantitative analysis does not include the potential for carbon emissions or carbon sequestration from effective forest management practices. The ponderosa pine forests throughout northern Arizona are unique when compared to many forest types around the United States due to their tendency to regenerate to shrubland and grassland after severe wildfires, thereby magnifying the carbon release caused by the wildfire.[60,61,62]

Criteria Emissions from Biomass Thermal Project

The air emissions analysis for a thermal-only project includes the processing and transport of biomass and natural gas. The biomass lifecycle framework began when the biomass feedstock was diverted from business-as-usual practices (e.g., after the slash pile was created for pile and burn or after sawmill residuals are collected). The bioenergy lifecycle begins after the slash pile is made. Biomass processing is predominately the chipping of slash piles but may include relocating slash piles if necessary to provide access for chipping equipment. No carbon reduction is attributed from forest-sourced feedstock coming from 4FRI or from feedstock coming from forest products manufacturing.

Natural gas analysis begins with the extraction of natural gas from gas reserves within North America such that it is transported exclusively via pipeline. Natural gas procurement refers to the extraction and processing of natural gas from these gas reserves until the gas is placed in a pipeline for distribution. Emissions factors for the life cycle analysis are shown in Table 26.

Table 26 illustrates the air quality benefits of biomass utilization to support forest management practices by reducing the wood wastes slated for pile and burn disposal. Quantifying the air quality benefits of diverting wood wastes in a holistic approach demonstrates the benefits of utilizing forest biomass despite the anticipated increased emission from the biomass boiler.

Gasification technology configurations are expected to have lower emissions profiles than direct combustion units due to the efficiencies associated with the utilization of a natural gas boiler. As seen in Table 26, the emission factors for natural gas boilers are significantly lower than biomass boilers. The utilization of a gasification configuration to provide heat would increase the overall air quality benefits for a biomass-to-heat project.

---

[60] Hurteau, M., Stoddard, M., Fule, P. The Carbon Costs of Mitigating High-Severity Wildfire in Southwestern Ponderosa Pine. *Global Change Biology, 17, 1516-1521*. 2011.
[61] Roccaforte, J., Fule, P., Chancellor, W., Laughlin, D. Woody Debris and Tree Regeneration Dynamics following Severe Wildfires in Arizona Ponderosa Pine Forests. *NRC Research Press*. 2011.
[62] Savage, M., Mast, Joy. How Resilient are Southwestern Ponderosa Pine Forests after Crown Fires. *Canadian Journal of Forest Research*, 35, 967-977. 2005.

Table 26. Projected Criteria Emissions from a Biomass Thermal System

	CO	NO_x	PM	VOC	CH_4
Biomass Utilization					
Biomass Boilers[63] (lbs/MMBtu$_{INPUT}$)	0.600	0.220	0.220	0.017	0.021
Biomass Processing[64,65] (lbs/MMBtu$_{INPUT}$)	0.018	0.013	0.009	0.001	0.001
Biomass Transport[66] (lbs/MMBtu$_{INPUT}$)	0.004	0.013	0.001	0.001	0.003
SUBTOTAL (lbs/MMBtu$_{DELIVERED}$)	**0.887**	**0.352**	**0.329**	**0.027**	**0.036**
Avoided Emissions					
Natural Gas Boilers[67] (lbs/MMBtu$_{INPUT}$)	0.008	0.049	0.007	0.005	0.002
Natural Gas Procurement[68] (lbs/MMBtu$_{INPUT}$)	0.031	0.050	0.000	0.010	0.039
Natural Gas Transport[69] (lbs/MMBtu$_{INPUT}$)	0.013	0.042	0.001	0.002	0.024
Pile and Burn[70,71] (lbs/MMBtu$_{INPUT}$)	0.446	0.021	0.046	0.035	0.021
SUBTOTAL (lbs/MMBtu$_{DELIVERED}$)	**0.702**	**0.206**	**0.076**	**0.072**	**0.111**
Net Emissions					
TOTAL (lbs/MMBtu$_{DELIVERED}$)	**0.186**	**0.146**	**0.253**	**-0.045**	**-0.075**
TOTAL (TPY)	**5.9**	**4.6**	**8.0**	**-1.4**	**-2.4**

Criteria Emissions from Biomass Combined Heat and Power Projects

Biomass CHP projects expand upon biomass thermal projects by producing electricity and utilizing waste heat to supplement existing heat demand. The lifecycle for this air emissions analysis includes emissions from the biomass facility and biomass procurement and transportation. Avoided emissions include reduced electricity demand from APS and reduced consumption of natural gas. APS has a generation profile that includes natural gas, renewable energy, distributed renewable energy, and electrical energy. Table 27 and Figure 27 show the projected electricity generation profile through 2027.

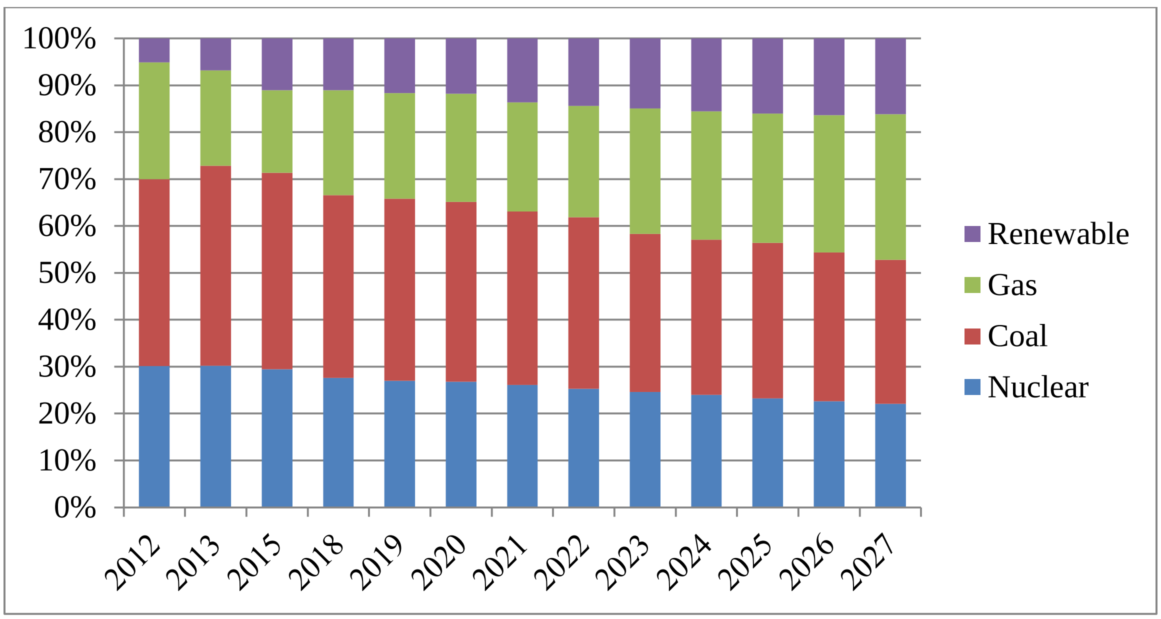
---

[63] EPA AP-42 Chapter 1, Section 6.
[64] Springsteen, B., Christofk, T., Eubanks, S., Mason, T., Clavin, C., Storey, B. Emission Reductions from Woody Biomass Waste for Energy as an Alternative to Open Burning. *Journal of the Air & Waste Management Association*, *61*(1), 63-68. 2011.
[65] Assumes emissions from biomass processing for biomass from forest products manufacturing are the same as from biomass from forest operations. This is a conservative estimate.
[66] GREET Version 1, October 2013.
[67] EPA AP-42 Chapter 1, Section 4.
[68] GREET Version 1, October 2013.
[69] Ibid.
[70] Springsteen, B., Christofk, T., Eubanks, S., Mason, T., Clavin, C., Storey, B. Emission Reductions from Woody Biomass Waste for Energy as an Alternative to Open Burning. *Journal of the Air & Waste Management Association*, *61*(1), 63-68. 2011.
[71] Assumes only 60% of the biomass utilized would have otherwise been piled and burned per the fuel blend as identified in the Biomass Resource Availability Review.

Table 27. Arizona Public Service Generation Profile, 2013 to 2027[72]

	2013	2014	2015	2016	2017	2018	2019	2020
Nuclear	30.2%	29.6%	29.4%	28.9%	28.2%	27.6%	27.0%	26.8%
Coal	42.6%	40.5%	41.9%	40.5%	39.5%	39.0%	38.9%	38.4%
Gas	20.4%	20.2%	17.6%	19.4%	21.1%	22.4%	22.5%	23.1%
Renewable	6.8%	9.8%	11.1%	11.2%	11.1%	11.1%	11.7%	11.8%
TOTALS	***100%***	***100%***	***100%***	***100%***	***100%***	***100%***	***100%***	***100%***
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**AVERAGE**
Nuclear	26.1%	25.3%	24.6%	24.0%	23.3%	22.6%	22.0%	***26.4%***
Coal	37.0%	36.6%	33.7%	33.1%	33.1%	31.7%	30.7%	***37.1%***
Gas	23.3%	23.7%	26.7%	27.4%	27.6%	29.3%	31.1%	***23.7%***
Renewable	13.7%	14.4%	14.9%	15.5%	16.0%	16.4%	16.1%	***12.8%***
TOTALS	***100%***	***100%***	***100%***	***100%***	***100%***	***100%***	***100%***	***100%***

Figure 27. Arizona Public Service Generation Profile, 2012 to 2027



The criteria emissions analysis includes the processing, transportation, and combustion of biomass, natural gas, and coal. The GREET model utilizes a life-cycle approach to evaluating the emissions from natural gas and coal. Nuclear and renewable electricity generation is assumed to have no air emissions. Table 28 identified emissions factors for biomass CHP projects and demonstrates the importance of accounting for avoided emissions from biomass feedstock.

Because there is limited emissions data from gasification facilities, Table 28 uses biomass boiler emissions rates for the small-scale biomass-to-electricity scenario. Gasification systems are

[72] APS Resource Procurement Plan.

expected to be cleaner than biomass boilers because of the high efficiency of the internal combustion engine and the producer gas conditioning which removes many of the potential pollutants. The net emissions findings in Table 28 are thereby expected to be conservative.

Note that if electricity emissions are attributed exclusively to coal generation,[73] the criteria pollutant emissions remain relatively similar to those in Table 28 since reduction in pile and burn material provides the majority of the emissions offsets.

Table 28. Projected Criteria Emissions from a Biomass-to-Electricity System

	CO	**NO_x**	**PM**	**VOC**	**CH_4**
Biomass Utilization					
Biomass Boilers[74] (lbs/kWh)	0.00233	0.00171	0.00025	0.00006	0.00015
Biomass Processing[75] (lbs/kWh)	0.00026	0.00019	0.00014	0.00001	0.00002
Biomass Transport[76] (lbs/kWh)	0.00052	0.00024	0.00001	0.00001	0.00001
SUBTOTAL (lbs/kWh)	**0.00311**	**0.00213**	**0.00040**	**0.00007**	**0.00018**
Avoided Emissions					
Electricity from Natural Gas[77] (lbs/kWh)	0.00010	0.00018	0.00001	0.00001	0.00003
Electricity from Coal[78] (lbs/kWh)	0.00080	0.00085	0.00008	0.00001	0.00001
Natural Gas Heat[79] (lbs/kWh)	0.00024	0.00064	0.00004	0.00008	0.00029
Pile and Burn[80,81] (lbs/kWh)	0.00691	0.00033	0.00071	0.00055	0.00033
SUBTOTAL (lbs/kWh)	**0.00931**	**0.00326**	**0.00097**	**0.00065**	**0.00065**
Net Emissions					
TOTAL (lbs/kWh)	**-0.00619**	**-0.00112**	**-0.00057**	**-0.00058**	**-0.00047**
TOTAL FOR A 2.5 MW PROJECT (TPY)	**-57.7**	**-10.4**	**-5.3**	**-5.4**	**-4.3**
TOTAL FOR A 10 MW PROJECT (TPY)	**-195.4**	**-35.4**	**-17.9**	**-18.2**	**-14.7**

[73] Per request by NAU staff due to the proximity of the Cholla Power Plant.
[74] Springsteen, B., Christofk, T., Eubanks, S., Mason, T., Clavin, C., Storey, B. Emission Reductions from Woody Biomass Waste for Energy as an Alternative to Open Burning. *Journal of the Air & Waste Management Association*, *61*(1), 63-68. 2011.
[75] Ibid.
[76] Ibid.
[77] GREET Version 1, October 2013.
[78] Ibid.
[79] Ibid.
[80] Springsteen, B., Christofk, T., Eubanks, S., Mason, T., Clavin, C., & Storey, B. Emission Reductions from Woody Biomass Waste for Energy as an Alternative to Open Burning. *Journal of the Air & Waste Management Association*, *61*(1), 63-68. 2011.
[81] Assumes only 60% of the biomass utilized would have otherwise been piled and burned per the fuel blend as identified in the Biomass Resource Availability Review.

Air Permitting

The entire NAU campus is subject to an air permit issued by the Air Quality Division of the Arizona Department of Environmental Quality (ADEQ). This permit covers the various natural gas boilers in both the north and south campus heating and cooling facilities. As the boilers in these facilities do not need to operate at full capacity on an annual basis, and do not result in the air pollutants CO, NO_x, SO_2, PM, PM_{10}, $PM_{2.5}$, VOC to individually exceed 100 tons per year (TPY), the NAU campus is not considered a Major Source under state and federal air regulations. The current air permit has limits on the number of hours that the boilers operate in order to keep the campus as a Synthetic Minor Source of air pollution. The principal constituent of concern is NO_x for the NAU permit and its current limit is around 75 TPY. However, the NAU air permit is currently being revised, and it is reported that the ADEQ is going to allow the revised permit to be based on natural gas usage directly, not operating hours. Reported emissions from fiscal year 2012/2013 for the entire campus are shown in Table 29.

Table 29. Fiscal Year 2012 to 2013 Report Emissions – NAU Campus[82]

CO (TPY)	NOx (TPY)	SO_2 (TPY)	PM (TPY)	VOC (TPY)
15.9	26.5	0.1	1.4	1.0

Air permitting agencies analyze and account for actual emissions and do not consider avoided emissions when issuing a permit. Air emissions potential for each development scenario are shown in Table 30.

As indicated in Table 30, Project Scenario 1 and Project Scenario 2 would allow NAU to remain below the 100 TPY thresholds associated with a Major Source permit. Project Scenario 3 would result in the need for a Major Source permit.

If NAU decides to install a 10 MW facility, the current Arizona Class II Synthetic Minor permit it now has for air quality at the campus would have to be revised into a full Title V permit. The current permit would likely be revised per Arizona Administrative Code Title 18 Chapter 2 Rule 320 (ACC-18-2-320) as a Significant Revision since the permit emission limits would be above the Title V threshold for CO, NOx, and PM (see Table 30). It should be noted that a synthetic minor facility is not subject to all the obligations of a major source facility. A Title V facility permit must include the requirements of all the regulations that apply to operations at a Title V facility. In particular, a Title V permit does place greater responsibility on the facility for emissions monitoring, reporting, and certifying compliance with the conditions of the permit.

As for permitting and annual compliance fees, ACC-18-2-326 indicates that annual compliance fees for a Title V permit should remain the same as what NAU is currently paying annually for its Synthetic Minor permit. Current annual fees paid by NAU are $23,210 (the Synthetic Minor permit category for NAU is "Other").[83] If a Title V permit is sought, the state does not have an

[82] Personal communication with James Biddle, Manager of Environmental and Industrial Hygiene Programs, NAU, on January 8 and 14, 2014.
[83] Personal communication with James Biddle on February 19, 2014.

application fee, but charges by the hour for permit application processing. The current rate is $151.20 per hour. Since the Significant Revision would only include one new unit (the 10 MW biomass power plant), several additional permit compliance requirements would be added, and a public hearing will likely be required prior to the issuance of the Title V permit. It could be assumed that AZ Air Quality Division staff could take at least 100 hours (100 times $151.20 or $15,120). A commensurate amount of time may likely be needed by NAU staff in preparing the Significant Revision application (and going through the approval process).

Table 30. Air Permitting Emissions

	CO	NOx	SO_2	PM	PM_{10}	$PM_{2.5}$	VOC
Project Scenario 1: Biomass-to-Heat – 20 MMBtu/hr Direct Combustion							
Biomass Boiler[84] (lbs/$MMBtu_{input}$)	0.600	0.220	0.025	0.220	0.200	0.120	0.017
Hourly Emissions[85] (lbs/hr)	17.143	6.286	0.714	6.286	5.714	3.429	0.486
Daily Emission (TPD)	0.206	0.075	0.009	0.075	0.069	0.041	0.006
Max. Potential Annual Emissions (TPY)	75.1	27.5	3.1	27.5	25.0	15.0	2.1
Expected Annual Emissions[86] (TPY)	***27.2***	***10.0***	***1.1***	***10.0***	***9.1***	***5.4***	***0.8***
Project Scenario 1: Biomass-to-Heat – 20 MMBtu/hr Gasification							
Biomass Gasification[87] (lbs/$MMBtu_{input}$)	0.008	0.049	0.001	0.007	0.005	0.002	0.005
Hourly Emissions[88] (lbs/hr)	0.229	1.400	0.017	0.200	0.143	0.057	0.143
Daily Emission (TPD)	0.003	0.017	0.000	0.002	0.002	0.001	0.002
Max. Potential Annual Emissions (TPY)	1.0	6.1	0.1	0.9	0.6	0.3	0.6
Expected Annual Emissions[89] (TPY)	***0.4***	***2.2***	***0.0***	***0.3***	***0.2***	***0.1***	***0.2***
Project Scenario 2: Biomass-to-Electricity – 2.5 MW Gasification							
Biomass Gasification[90] (lbs/hr)	4.922	0.949	0.237	0.376	0.376	N/A	0.929
Daily Emission (TPD)	0.059	0.011	0.003	0.005	0.005	N/A	0.011
Max. Potential Annual Emissions (TPY)	21.6	4.2	1.0	1.6	1.6	N/A	4.1
Expected Annual Emissions[91] (TPY)	***18.3***	***3.5***	***0.9***	***1.4***	***1.4***	***1.4***	***3.5***
Project Scenario 3: Biomass-to-Electricity – 10 MW Direct Combustion							
Biomass Boiler[92] (lbs/$MMBtu_{input}$)	0.600	0.220	0.025	0.220	0.200	0.120	0.017
Hourly Emissions (lbs/hr)	93.000	34.100	3.875	34.100	31.000	18.600	2.635
Daily Emission (TPD)	1.116	0.409	0.047	0.409	0.372	0.223	0.032
Max. Potential Annual Emissions (TPY)	407.3	149.4	17.0	149.4	135.8	81.5	11.5
Expected Annual Emissions[93] (TPY)	***301.4***	***110.5***	***12.6***	***110.5***	***100.5***	***60.3***	***8.5***

[84] EPA AP-42 Chapter 1, Section 6.
[85] Assumes 70% system efficiency.
[86] Based on a 36.2% capacity factor as identified in the Energy Load Assessment.
[87] EPA AP-42 Chapter 1, Section 4.
[88] Assumes 70% system efficiency.
[89] Based on a 36.2% capacity factor as identified in the Energy Load Assessment.
[90] San Joaquin Valley Air Pollution Control District (Fresno, CA) Permit Number N-1093805, N-8071-1-0, '-2-0. The emission factors account for both the flare and the gasification unit and incorporate time-of-day utilization. The emissions numbers are scaled up to 2.5 MW.
[91] Based on an 85% capacity factor due to operational constraints for O&M. The Energy Load Assessment indicates a technical ability to run at 100% capacity due to the electricity demand.
[92] EPA AP-42 Chapter 1, Section 6.
[93] Based on a 74% capacity factor as identified in the Energy Load Assessment.

Greenhouse Gas Impacts

NAU calculated greenhouse gas using the Clean Air-Cool Planet Campus Carbon Calculator. The Campus Carbon Calculator is used to track comprehensive greenhouse gas emissions. The calculator assumes no carbon footprint for the utilization of wood chips. Table 4 shows the potential impacts of greenhouse gas reductions based on the Clean Air-Cool Planet Campus Carbon Calculator given the 2012 base of 61,595 MT of CO_2e.[94] Results were calculated based on the projected reduction of electricity and fossil fuel use.

Table 31. Potential for Greenhouse Gas Offsets[95]

	POTENTIAL CARBON REDUCTION (MT CO_2e)	PERCENT REDUCTION
PROJECT SCENARIO 1	3,292	5.3%
PROJECT SCENARIO 2	10,111	16.4%
PROJECT SCENARIO 3	33,155	53.8%

Findings

The air emissions analysis indicates that when the full air emissions profile is considered, biomass energy reduces air emissions across both criteria and greenhouse gas pollutants.

For the purposes of permitting, only direct emissions (without offsets) are included. The revised ADEQ air permit is currently under development by NAU, and the ADEQ is demonstrating the NO_x emissions at the NAU campus will be in the 26 TPY range, which is significantly under 100 TPY, the Major Source threshold. For a variety of reasons, the NAU campus wishes to not become a Major Source. Thus, using the NO_x TPY value in Table 30, the following development scenarios would likely fit within the revised NAU permit and not exceed the Major Source threshold:

- Biomass-to-Heat: 20 MMBtu/hr Direct Combustion
- Biomass-to-Heat: 20 MMBtu/hr Gasification
- Biomass-to-Electricity: 2.5 MW Gasification

The fourth development scenario, biomass-to-electricity: 10 MW Direct Combustion in and of itself would exceed the 100 TPY Major Source threshold for not only NO_x, but CO and PM as well.

[94] TSS was not provided access to NAU's filled-out Clean Air-Cool Planet Campus Carbon Calculator; 61,595 is based on communication with NAU project team.
[95] Calculated with Clean Air-Cool Planet Campus Carbon Calculator based on APS average electricity blend and the projected load displacement per the Energy Load Assessment.

ECONOMIC ANALYSIS

The economic analysis reviews the direct financial impact along with the societal benefits and costs from project development. This economic analysis will review the impacts of a project compared to the avoided cost from electricity and natural gas demand, impacts to forest health and restoration, and local jobs.

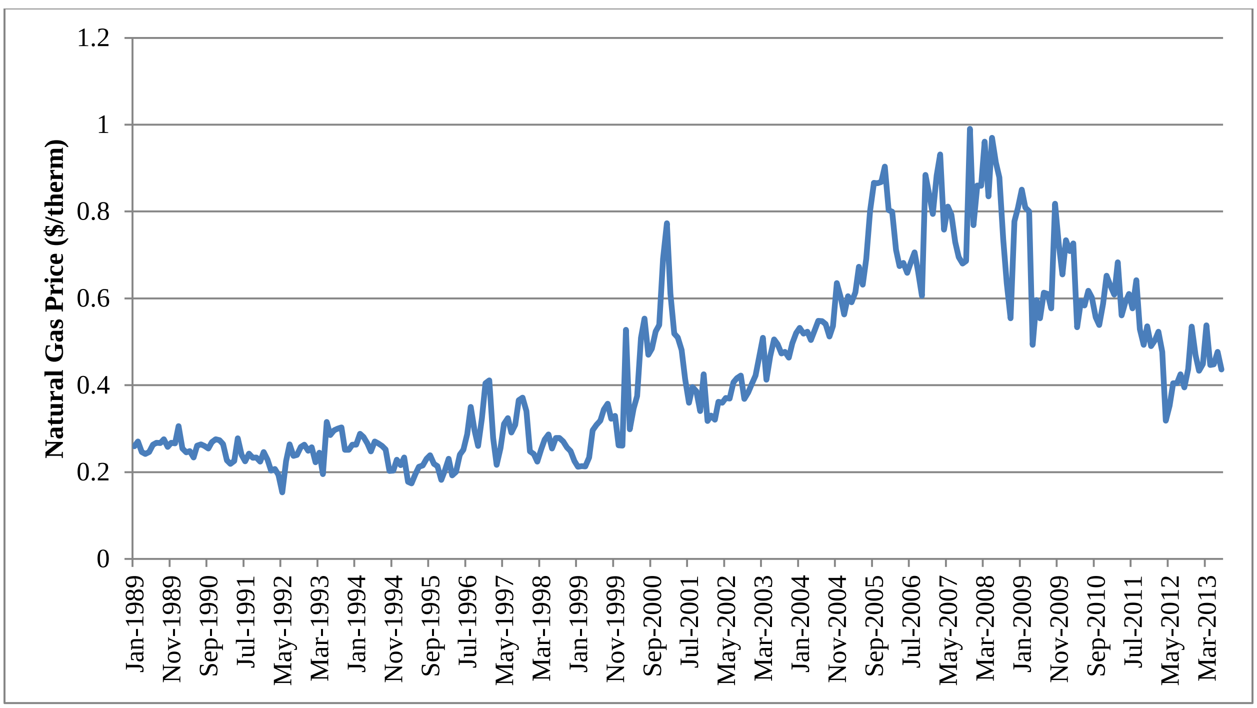
Fossil Fuel Pricing

Natural Gas Pricing

Natural gas is sourced on the open market by NAU and transported via UniSource Energy Services (UES) under a NSP-T1 schedule. A T1 service schedule is for end-use customers transporting more than 120,000 therms per year (customers are allowed to aggregate meters that provide over 50,000 therms per year). This contract follows a negotiated sales program which is a rate schedule negotiated between UES Services and NAU.

Historic natural gas pricing for Arizona city gate prices is available through 1989 (Figure 28). Figure 28 indicates significant fluctuation in natural gas pricing over the last two decades. NAU has requested that TSS use $0.80 per therm as the price for natural gas. This is consistent with the current pricing, including bulk purchasing and transmission charges.[96]

Figure 28. Arizona City Gate Natural Gas Pricing



Source: U.S. Energy Information Administration

[96] The NAU natural gas bill for November, 2013 resulted in an all-in price of $0.76 per therm.

Electricity Pricing

Electricity is provided by APS under Schedule E-34. Schedule E-34 is a rate schedule that is available to customers whose monthly maximum demand registers 3,000 kW or more for three consecutive months in any continuous twelve-month period. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified. The schedule E-34 service charges the following rates:

- Customer Accounts Charge: $0.601/day
- Meter Reading Charge: $0.066/day
- Billing Charge: $0.073/day
- Revenue Cycle Service Charge
  - Self-Contained Meters: $0.395/day or;
  - Instrument-Rated Meters: $1.036/day or;
  - Primary: $3.088/day or;
  - Transmission: $25.421/day
- Transmission Charge: $1.776/kW
- Delivery Charge
  - Secondary Service: $8.027/kW
  - Primary Service: $6.746/kW
  - Transmission Service: $0.375/kW
- Generation Charge: $10.127/kW
- Systems Benefit Charge: $0.00297/kWh
- Generation Charge: $0.03368/kWh

NAU uses two meters and receives E34 service resulting in the following bundled electricity changes:

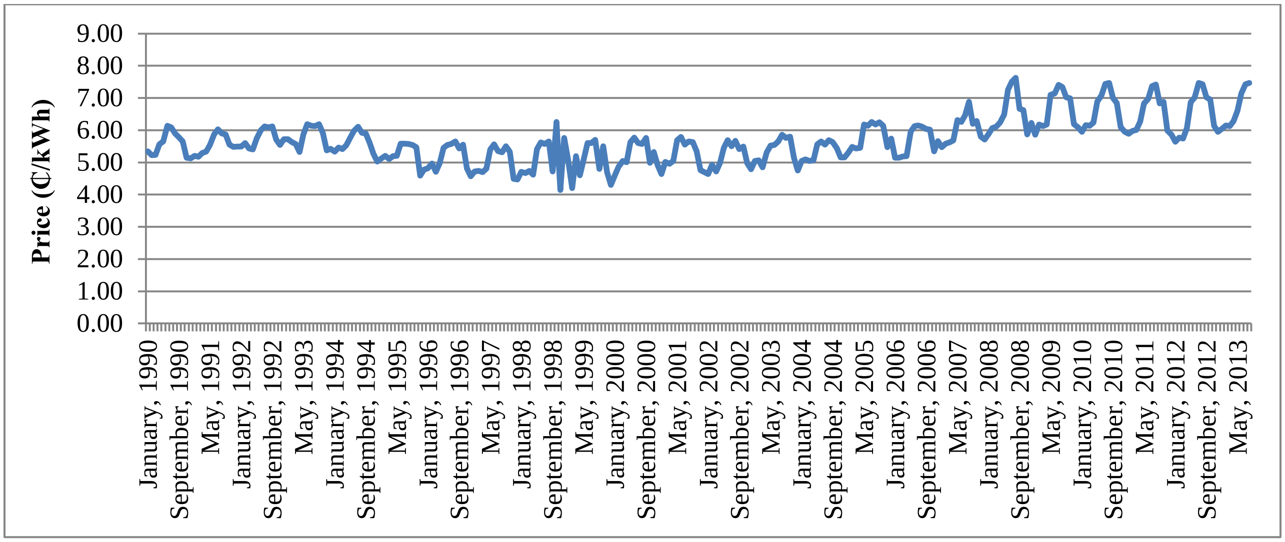
- Daily Charges: $3.828/day
- Power Charges: $18.649/kW
- Energy Charges: $0.03665/kWh

Additionally, NAU purchases 10% of its energy from the Green Choice Program, which adds a $0.0102/kWh premium to 10% of all energy charges, resulting in an effective energy charge of $0.03767/kWh.

When reviewing a behind-the-meter application, adding the demand charge for 2.5 MW yields a total electricity price of approximately $0.06357/kWh. The demand charge, however, is measured as the highest demand in any 15-minute interval over the billing period. Therefore, these savings are only realized if the biomass plant has no outages for an entire month.

Historic electricity pricing for the industrial sector in Arizona is displayed in Figure 29. Note that this industrial electricity price is higher than the Schedule E-34 tariff utilized by NAU; however, Figure 29 provides an understanding for the electricity price trends over the last 20 years.

Figure 29. Historic Electricity Prices for the Industrial Sector in Arizona



Source: U.S. Energy Information Administration

Note that electricity prices have remained relatively stable over the last two decades despite significant fluctuations in natural gas pricing. This is due to the energy diversity within Arizona, which utilizes coal, nuclear, and natural gas as primary energy sources. Figure 29 illustrates the traditional time of delivery rate structure, which increases pricing in the summer during times of higher demand. NAU does not have a time-of-delivery component in their rate schedule.

Based on the APS resource plan,[97] electricity prices are expected to increase by 86% to 96% by 2027 – approximately a 4.4% electricity price increase over the 15 year period. This includes the increased adoption of renewables and phasing out coal. The levelized price to account for this escalation is 28.9% higher than the current price. For NAU, this would represent a levelized rate of $0.0473 per kWh.

Utility Rate Schedules

TSS has performed a high-level review of the APS and UES rate schedules to develop a basic understanding of how bioenergy development may affect the current status. TSS also reviewed alternative rate schedules but did not discuss alternatives directly with APS or UES and has not negotiated in any way with APS or UES. If a bioenergy project moves, NAU should contact APS or UES to identify exactly how a project may impact their existing contract and relationship.

In the financial analysis sections, TSS indicates what is expected based on reading the rate schedules; however, comments should be read as TSS's interpretation only and should be discussed with the utility provider.

Project Scenario 1 and 2 are not expected to change the existing natural gas or APS rate structures. Project Scenario 3 would require a change in the APS rate structure for electricity

[97] APS 2012 Resource Procurement Plan.

using APS Schedule E-56 for backup power. Total costs will vary depending on the technology and operations; therefore, TSS cannot predict the total cost implications of the new schedule. Charges under the E-56 rate schedule are summarized below and are significantly higher than those currently paid with E-34 (although the energy and power demand should be significantly lower).

- Backup Power: $0.59/kW-day
- Excess Power: $54.082/kW
- All remaining power shall be billed at the applicable general rate schedule.

Financial Analysis: Project Scenario 1

The financial analysis accounts for the revenues and costs associated with the biomass-to-heat project configurations. While direct combustion and gasification configurations are significantly different, their pricing is expected to be comparable. Gasification systems and direct combustion systems should be compared in a competitive bid process. Assumptions include:

- $4,200,000 – Total Project Costs[98,99,100,101]
- 36.2% – Annual Capacity Factor (Energy Load Assessment)
- 20 MMBtu per hr – Boiler Size (Technology Analysis)
- 71% – System Efficiency
- Feedstock high heat value of 8,400 Btu per dry pound[102]
- 50% – Moisture Content of Wood Feedstock[103]
- $10,000 per year – Labor Costs[104]
- $18,000 per year – Amortized Maintenance[105]
- $28 per BDT – Feedstock Cost (Biomass Resource Availability Review)
- 75% – Debt to Equity Ratio
- 10 years – Debt Term
- 5% – Interest Rate on Debt
- 30 years – Project Life

Based on the assumptions, Table 32 shows the expected internal rate of return and simple payback period for a project based on the price of natural gas. The findings in Table 32 do not account for any cost savings associated with avoiding the need to purchase a replacement natural

[98] Capital cost was increased to account for the need to update the South Campus Heating and Cooling Plant.
[99] U.S. EPA Combined Heat and Power Partnership. "Biomass CHP Catalog. Chapter 7. Representative Biomass CHP System Cost and Performance Profiles." September, 2007. http://www.epa.gov/chp/documents/biomass_chp_catalog_part7.pdf
[100] Lowe, L. Utah Department of Natural Resources Division of Forestry, Fire and State Lands. "Assessment: Potential for Using Woody Biomass for Heat and/or Power in Utah's Institutions and Industries." December, 2006. http://www.ffsl.utah.gov/images/forestry/woody-biomass/UTBoilerAssessment.pdf
[101] In consultation with Jonathan Heitzinger, Assistant Director of Utility Services, NAU
[102] Discussions with Heath Hildebrand, Plant Manager, Novo Power.
[103] Ibid.
[104] TSS estimate.
[105] TSS estimate.

gas boiler. Also, the development of a biomass boiler is not expected to affect the price for procurement of natural gas.

Table 32. Project Financial Outcome – Biomass to Heat

NATURAL GAS PRICE ($/THERM)	INTERNAL RATE OF RETURN (%)	SIMPLE PAYBACK PERIOD (YEARS)
$0.56[106]	1.8%	23.6
$0.80[107]	9.3%	12.7
$1.81[108]	55.8%	4.3

Financial Analysis: Project Scenario 2

The financial analysis accounts for the revenues and costs associated with the small-scale biomass to electricity project configurations. Assumptions include:

- $12,500,000 – Total Project Costs[109,110]
- 85% – Annual Capacity Factor (Energy Load Assessment)
- 2.5 MW – Gasification Project Size (Technology Analysis)
- 15,500 Btu per kWh – Heat Rate
- Option 1: 0 – Waste Heat Utilization to Displace Natural Gas
- Option 2: 4 MMBtu per hour at 74.0% CF – Waste Heat Utilization from Jacket Water Rejection
- Feedstock high heat value of 8,400 Btu per dry pound[111]
- 50% – Moisture Content of Wood Feedstock[112]
- $400,000 per year – Labor Costs[113]
- $600,000 per year – Amortized Maintenance[114]
- 75% – Debt to Equity Ratio
- 20 years – Debt Term
- 6% – Interest Rate on Debt
- 20 years – Project Life
- 15% – Internal Rate of Return

---

[106] Lowest price since 2000 based on Figure 28 and NAU's price structure.
[107] Current price, as directed by the NAU project team.
[108] Highest price since 2000 based on Figure 28 and NAU's price structure.
[109] U.S. EPA Combined Heat and Power Partnership. "Biomass CHP Catalog. Chapter 7. Representative Biomass CHP System Cost and Performance Profiles." September, 2007. http://www.epa.gov/chp/documents/biomass_chp_catalog_part7.pdf
[110] Lowe, L. Utah Department of Natural Resources Division of Forestry, Fire and State Lands. "Assessment: Potential for Using Woody Biomass for Heat and/or Power in Utah's Institutions and Industries." December, 2006. http://www.ffsl.utah.gov/images/forestry/woody-biomass/UTBoilerAssessment.pdf
[111] Discussions with Heath Hildebrand, Plant Manager, Novo Power.
[112] Ibid.
[113] TSS estimate.
[114] TSS estimate.

- 1% – Inflation except for electricity pricing

If the small-scale application is used to reduce the baseload of the north campus meter, the project is not expected to impact the existing rate schedule, as it will still qualify for the Schedule E-34 requirements. NAU may shift to Schedule EPR-6 which allows for the sale of excess power generation (at $0.02789/kWh) while still purchasing power under the applicable rate schedule. NAU is not expected to create excess power under this project scenario and no revenues have been attributed to excess power sales.

Based on the assumptions, Table 32 shows the required levelized price of electricity as a function of feedstock cost.

Table 33. Project Financial Outcome – Biomass to Electricity, 2.5 MW

FEEDSTOCK PRICE ($/BDT)	LEVELIZED COST OF ELECTRICITY WITHOUT CHP ($/KWH)	LEVELIZED COST OF ELECTRICITY WITH CHP ($/KWH)
$0	$0.127	$0.117
$10	$0.137	$0.127
$20	$0.146	$0.136
$30	$0.156	$0.146
$40	$0.166	$0.156

Financial Analysis: Project Scenario 3

The financial analysis accounts for the revenues and costs associated with the large-scale biomass to electricity project configurations. Assumptions include:

- $30,000,000 – Total Project Costs
- 85% – Annual Capacity Factor (Energy Load Assessment)
- 10 MW – Direct Combustion Project (Technology Analysis)
- 15,500 Btu per kWh – Heat Rate
- 30 MMBtu per hour at 24.4% CF – Waste Heat Utilization to Displace Natural Gas (South Campus Only)
- Feedstock high heat value of 8,400 Btu per dry pound[115]
- 50% – Moisture Content of Wood Feedstock[116]
- $2,400,000 per year – O&M Costs[117,118,119,120]
- $1,000,000 per year – Fixed Costs[121,122,123,124]

115 Discussions with Heath Hildebrand, Plant Manager, Novo Power.
116 Ibid.
117 International Renewable Energy Agency (IRENA), Renewable Energy Technologies: Cost Analysis Series, Biomass for Power Generation. Volume 1, Issue 1.
118 Viburnum Economics Development Area Corporation, “Feasibility Study for a Biomass Electrical Power Plant in the Viburnum Region.” March 12, 2012.
119 U.S. EPA, “Biomass Combined Heat and Power Catalog of Technologies,” September 2007.
120 Discussions with representatives from Ameresco’s Phoenix office.

- 75% – Debt to Equity Ratio
- 20 years – Debt Term
- 6% – Interest Rate on Debt
- 20 years – Project Life
- 15% – Internal Rate of Return
- 1% – Inflation except for electricity pricing

The development of a large biomass-to-electricity facility will significantly alter the APS schedule, as NAU would no longer qualify for Schedule E-34. Instead, it is expected that NAU would switch to Schedule E-56 for backup and maintenance power. Schedule E-56 includes monthly charges for connection (regardless of electricity use from APS) and specific rates for backup and maintenance power. The monthly charges are based on the general applicable rate service to the facility and are not anticipated to be a large cost relative to the annual O&M and Fixed Costs required for plant operation.

Additional air permit fees are included in the capital cost and the annual fixed costs.

Based on the assumptions, Table 32 shows the required levelized price of electricity as a function of feedstock cost.

Table 34. Project Financial Outcome – Biomass to Electricity, 10 MW

FEEDSTOCK PRICE ($/BDT)	LEVELIZED COST OF ELECTRICITY ($/KWH)
$0	$0.084
$10	$0.094
$20	$0.104
$30	$0.113
$40	$0.123

Economic Analysis

Job Creation

Operations and maintenance of the biomass thermal facility will require some operations staff time, but not enough to justify a dedicated full-time position. The biomass-to-electricity facilities will require dedicated staff focused on operations, maintenance and feedstock sourcing. A 1999 study sponsored by the National Renewable Energy Laboratory confirmed that approximately 4.9 direct jobs per megawatt[125] of generation capacity was indicative of

[121] International Renewable Energy Agency (IRENA), Renewable Energy Technologies: Cost Analysis Series, Biomass for Power Generation. Volume 1, Issue 1.
[122] Viburnum Economics Development Area Corporation, “Feasibility Study for a Biomass Electrical Power Plant in the Viburnum Region.” March 12, 2012.
[123] U.S. EPA, “Biomass Combined Heat and Power Catalog of Technologies,” September 2007.
[124] Discussions with representatives from Ameresco’s Phoenix office.
[125] The Value of the Benefits of U.S. Biomass Power, NREL, 1999.

commercial biomass power plants in the U.S. These jobs include feedstock sourcing, plant operations, plant maintenance and administration.
For the biomass thermal facility, the primary job creation opportunity lies with feedstock sourcing. The collection, processing and transport of forest biomass feedstock is a relatively labor intensive process. Field equipment such as feller-bunchers, skidders, chippers and chip trucks require skilled laborers to operate. In addition, skilled technicians are needed to maintain and repair this equipment. While field operations are seasonal, there are typically eight to ten months per year[126] of active operations, depending on weather conditions and location of operations. Assuming feedstock demand of approximately two truckloads per day (biomass to heat scenario), TSS estimates that about three new jobs will be created.

In addition to the benefits of job creation, there will be ancillary economic benefits for enterprises engaged in support services including (but not limited to) tire shops, petroleum product distributors, and restaurants.

Forest Health and Societal Benefits

The utilization of forest biomass can provide a significant number of societal benefits that are not captured in the cost and benefit analysis or financial model of a bioenergy project, some of which are in addition to typical benefits of other renewable energy technologies.[127]

- ***Promotes healthy forests and defensible communities.*** Provides a ready market value for woody biomass material generated as a byproduct of forest management, hazardous fuels reduction and forest restoration activities.[128] This helps encourage projects that contribute to defensible communities and healthy forest ecosystems through the generation of income to fund additional treatment activities.

- ***Protects key watersheds.*** A significant portion of Arizona's in-state water resources flow from forested landscapes. Healthy forest ecosystems in these upland watersheds ensure that sustainable quantities of high quality water for both domestic and agricultural uses will continue to flow.[129,130,131] This is particularly important given the predicted effects of climate change on future water production and the ability of forest management projects to protect and enhance both quality and quantity of water from forested

[126] Discussions with High Desert Investment, Perkins Timber Harvesting.
[127] C. Mason, B. Lippke, K. Zobrist et al., "Investments in Fuel Removals to Avoid Forest Fires Results in Substantial Benefits," Journal of Forestry, January/February 2001, pp. 27-31.
[128] M. North, P. Stine, K. O'Hara, W. Zielinski, and S. Stephens, "An Ecosystem Management Strategy for Sierran Mixed-conifer Forests," USDA Forest Service, PSW General Technical Report PSW-GTR-220, 2009.
[129] R.R. Harris and P.H. Cafferata, Effects of Forest Fragmentation on Water Quantity and Quality. Paper presented to the Conference on California Forest Futures, Sacramento, CA, May 23-24, 2005.
[130] J.D. Murphy, D.W. Johnson, W.W. Miller, R.F. Walker, E.F. Carrol, and R.R. Blank, "Wildfire Effects on Soil Nutrients and Leaching in a Tahoe Basin Watershed," Journal of Environmental Quality, Volume 35, 2006, pp. 479-489.
[131] Numerous studies led by Lee H. MacDonald, Colorado State University, Department of Forest, Rangeland, and Watershed Stewardship.

landscapes. Increased water yield of 9% to 16%[132] could result should additional forest acres be thinned within a watershed.

- ***Provides net air quality and greenhouse gas benefits.*** Forest biomass material that would otherwise be disposed of by open pile burning, in prescribed broadcast burns, or would have been consumed in a wildfire, can be utilized in a controlled manner to provide renewable energy (energy conversion units including boilers and gasifiers that are equipped with Best Available Control Technology), thus reducing air emissions and improving regional air quality. The air quality benefits are significant with 90+% reduction in carbon monoxide, methane, and volatile organics, 70+% reduction in particulate matter, and a 40+% reduction in nitrogen oxides and carbon dioxide when compared to business-as-usual practices.[133,134,135,136] An additional climate change benefit results from replacing fossil fuel fired power generation with renewable bioenergy.

- ***Reduces waste going to landfills***. Wood waste destined for landfills can be recovered and utilized, thus extending the service life of landfills, reducing the need to develop additional landfill facilities, producing renewable energy, and reducing greenhouse gases.

- ***Protects transmission/distribution infrastructure.*** Power distribution infrastructure in Arizona is significant. Many of the state's generation assets utilize transmission and distribution systems located in forested regions to deliver generation to load centers. Forest management and hazard reduction projects can reduce the likelihood of wildfire damage to valuable power distribution infrastructure.

- ***Utilizes renewable and sustainable feedstocks.*** Bioenergy facilities are sized to utilize biomass from sources that continue to produce biomass in a long-term, sustainable way.

- ***Reduces wildfire suppression costs.*** Forest management fuel reduction activities significantly reduce the economic costs for fighting wildfires. Fire suppression costs averaged $695 to $765 per acre between 1996 and 2007.[137,138]

---

[132] R.C. Bales, et al., "Forests and Water in the Sierra Nevada: Sierra Nevada Watershed Ecosystem Enhancement Project," November 2011.
[133] Findings from the Air Emissions Impact Analysis.
[134] Springsteen, B., Christofk, T., Eubanks, S., Mason, T., Clavin, C., Storey, B., Emission Reductions from Woody Biomass Waste for Energy as an Alternative to Open Burning. *Journal of the Air & Waste Management Association*, *61*(1), 63-68. 2011.
[135] Jones, G., Loeffler, D., Calkin, D., Chung, W. Forest Treatment Residues for Thermal Energy Compared With Disposal by Onsite Burning: Emissions and Energy Return. Biomass and Bioenergy, Volume 34, 2010, pp. 737-746.
[136] Lee, C., Erickson, P., Lazarus, M., Smith, G., 2010. Greenhouse Gas and Air Pollutant Emissions of Alternatives for Woody Biomass Residues. *Stockholm Environmental* Institute, November 2010.
[137] K.M. Gebert et al., "Estimating Suppression Expenditures for Individual Large Wildland Fires," Western Journal of Applied Forestry, 2007, pp. 188 to 196.
[138] Fitch, R., Kim, Y., Waltz, A. Forest Restoration Treatments: Their Effect on Wildland Fire Suppression Costs. *Northern Arizona University Ecological Restoration Institute*. May 2013.

- ***Reduce Landscape Conversion.*** Historical data has shown that ponderosa pine forests in northern Arizona have difficulty with regenerating after severe wildfires.[139] Forested landscapes can convert to shrubland and grassland, reducing the total forested landscape and reducing the region's ability to sequester carbon.

[139] Savage, M., Mast, Joy. How Resilient are Southwestern Ponderosa Pine Forests after Crown Fires. *Canadian Journal of Forest Research*, 35, 967-977. 2005.

RECOMMENDATIONS AND NEXT STEPS

Bioenergy development in Arizona is challenging largely due to the availability of relatively low-cost natural gas and relatively low-cost electricity. However, the Flagstaff area is surrounded by biomass resources predominantly through the 4FRI stewardship contract. NAU is in an optimal position to utilize the available biomass, consequently reducing pile and burn emissions, supporting local forest management, and increasing their utilization of renewable energy. TSS recommends the following steps to move forward with bioenergy development.

- Keep in touch with Good Earth Power, as there may be partnership opportunities that would help reduce the capital cost of a project and/or facilitate delivery of reduced cost feedstock.
- Start small; there is a learning curve when transitioning from natural gas to biomass. Small projects tend to allow greater flexibility and time for operations staff to learn the biomass model.
- TSS recommends Project Scenario 1 for next steps as the most economically attractive model.
- Consider reaching out to Good Earth Power to initiate discussions regarding a long-term feedstock purchase and sale agreement.
- Structured outreach and communication to the NAU and Flagstaff communities will be critical to community acceptance.
- Consider applying for the Woody Biomass Utilization Grant from the USFS for funding engineering and design work.
- NAU may want to monitor the rapidly expanding biochemical/advanced biofuels market due to their location amidst a significant forest biomass resource and the potential to partner with a biochemical/biofuels manufacturer to provide a unique opportunity for student and university research.