IV. Options Analysis

A. Basis of Evaluation

The options evaluated were based on existing conditions, campus growth, a level of economics and a realistic approach that the UW could use to implement or analyze further from evolving conditions. These conditions include actual campus growth, unforeseen conditions, and developing technologies for potential use on campus. The evaluation also considered existing GHG emissions and identified potential emission reductions for each option that could be applied to meet the UW commitment to American College and UW Presidents Climate Commitment (ACUPCC).

B. Heating System

1. Fuel Assessment

a) Fuel Characteristics

Several fuels were compared based upon net cost and carbon dioxide emissions. In addition to the existing fuels (natural gas, No. 2 fuel oil and coal), three biomass fuels were examined including wood pellets, dry logs and green logs. The net cost includes the efficiency of a boiler utilizing the respective fuel. A summary of the fuel characteristics is presented in the table below.

Table IV-A-1

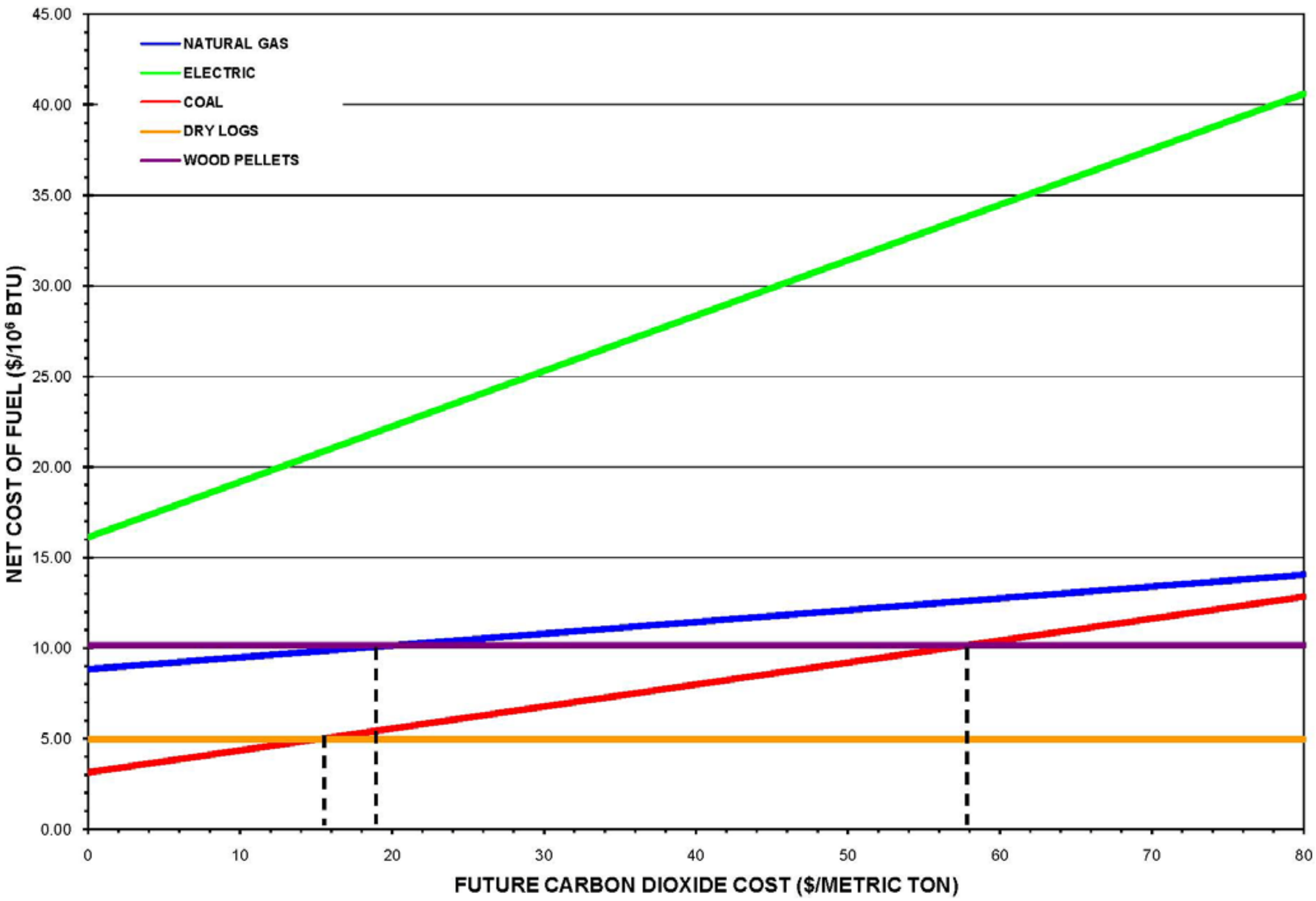
FUEL	COST ($)	HIGHER HEAT VALUE	BOILER EFFICIENCY (%)	UNIT COST		CARBON DIOXIDE	
				GROSS ($/$10^6$ BTU)	NET ($/$10^6$ BTU)	GROSS (LB/10^6 BTU)	NET (LB/10^6 BTU)
NATURAL GAS	$7.20 PER DECATHERM	100,000 BTU/THM	81.5	7.20	8.83	117	117
DISTILLATE OIL	$2.36 PER GALLON	140,000 BTU/GAL	85.3	16.86	19.76	169	169
ELECTRIC	$0.055 PER KWH	3,413 BTU/KWH	100.0	16.12	16.12	673	673
COAL	$55.26 PER TON	10,400 BTU/LB	84.7	2.66	3.14	226	226
WOOD PELLETS (15% MC)	$175 PER TON	10,450 BTU/LB	82.3	8.37	10.17	184	---
WOOD - DRY LOGS (30% MC)	$55 PER TON	7,000 BTU/LB	79.1	3.93	4.97	184	---
WOOD - GREEN (50% MC)	$55 PER TON	5,000 BTU/LB	72.4	5.50	7.60	184	---

NOTES:
1. ASSUME FLUE GAS TEMPERATURE = 350°F WITH AIR PREHEATER
2. EXCESS AIR RATES: GAS = 15%
   OIL = 25%
   COAL = 50%
   WOOD = 50%
3. CONVECTIVE / RADIATED LOSSES = 2% AT 100% FIRING RATE
4. ELECTRIC CO_2 IN WYOMING IS 2.30 POUNDS PER KWH
5. COST OF TRANSPORT OF WOOD = $0.25 / MILE-TON @ 100 MILES = $25/TON

b) Carbon Dioxide Tax Sensitivity

A sensitivity analysis was also performed on the net fuel cost with the addition of the potential carbon dioxide tax. A summary of the sensitivity analysis is presented in Figure IV-A-1 below and is based on 2008 dollars.

Figure IV-A-1



As the potential carbon tax increases, the cost of electric, natural gas, and coal will increase and possibly surpass the cost of biomass. For example, currently coal is the lowest cost fuel but with the application of a carbon dioxide tax of $15/metric ton, dry logs become the most cost effective fuel.

2. Initial CEP Options Evaluation, Economics, and Phasing Analysis

a) Central Energy Plant Improvements with Coal (Generation Option Nos. 1 & 1A)

Given the operational difficulties at the Central Energy Plant (CEP) with the use of the existing quality of coal, several recommendations for improvements to the existing equipment have been developed. These recommendations are considered the Base Option for CEP upgrades.

- Add Cover to Truck Drop Area:

  As illustrated in the photo below, the truck drop area is exposed to the elements and should be covered to prevent snow and rain from entering into the Macawber Denseveyor. All attempts should be made to keep the coal and pneumatic conveying system as dry as possible. This addition will also assist moisture reduction for any type of fuel delivered to the drop area.

  Figure IV-A-2

- Replace Existing Feeders:

  It is recommended to replace the existing 30-year old RotoGrate Stoker feeders (three per boiler) with new 18" Detroit RotoStoker Underthrow fuel distributors (three per boiler) as previously proposed by Detroit Stoker Company. It is recommended that flue gas recirculation (FGR) be added as part of this upgrade.

  Although in good condition for their age, the existing feeders are reaching the end of their remaining useful life (less than 5 years). The updated technology of the new feeders and FGR enhances the ability of the boilers to handle the inconsistency of the existing coal and better handling of a fuel mixture of coal and biomass. The fuel distributors are designed to handle coal with a maximum top size of 2" and a maximum of 65% less than 1/4" (fines).

  The addition of FGR not only reduces thermal NO_x emissions by reducing the flame temperature of combustion, but also assists the distribution of coal as it mixes with overfire air. This added effect clears the feeder of coal fines as well as provides a drying mechanism for wet coal. The overall effect of FGR and overfire mixing creates clearing of fines and cooling of the distributor to prevent feeder fires.

- Replace Existing Drag-Chain Conveyor:

  The existing drag-chain conveyor that transports coal from the coal storage silos to the individual boiler coal bunkers via a second Denseveyor continues to be an operational and maintenance difficulty for the CEP. The conveyor has reached the end of its remaining useful life, and it is recommended to be replaced with a different type of conveying system (i.e. auger-screw type). The existing drag-chain conveyor is illustrated below:

  Figure IV-A-3

- Replace Existing Steam Exhauster and Add a Mechanical Exhauster:

  The existing steam exhauster for the ash system is the single point of failure for the entire system. If the steam exhauster is down for maintenance or repair, the CEP cannot pull ash and burn coal. The steam exhauster is nearing the end of its remaining useful life and should be replaced. It is recommended to retrofit the existing ash pull system with a mechanical exhauster in parallel with the steam exhauster for added redundancy.

- Separate Fly Ash from Bottom Ash (As Required):

  Lastly, it is recommended to separate the existing fly ash collection system from the bottom ash collection system as required for ash disposal issues. By separating the ash it will reduce the quantity that has to be permitted or removed from the campus. The existing tunnel to the ash silo has sufficient room for parallel ash removal piping to a redundant silo. The existing tunnel and the ideal location for separating these systems are illustrated below:

Figure IV-A-4

Figure IV-A-5

Fly ash can be sold and used in several manufacturing processes such as asphalt and wall-board. Bottom ash is typically treated and disposed of in a landfill. As the current means of ash disposal may be discontinued, several alternatives are recommended for investigation and are listed below:

- Waste Management Disposal, North Weld Landfill, www.wmdisposal.com
- Boral Material Technologies, Harry Ruth, Supervising Engineer, 303-779-8366, info@boral.com
- Existing Landfill in Casper, WY, Brian Williams, Landfill Supervisor, 307-235-8400, bwilliams@cityofcasperwi.com
- New Landfill on UW Property.

- Install Separator Screen (As Required For Coal Quality Issues):

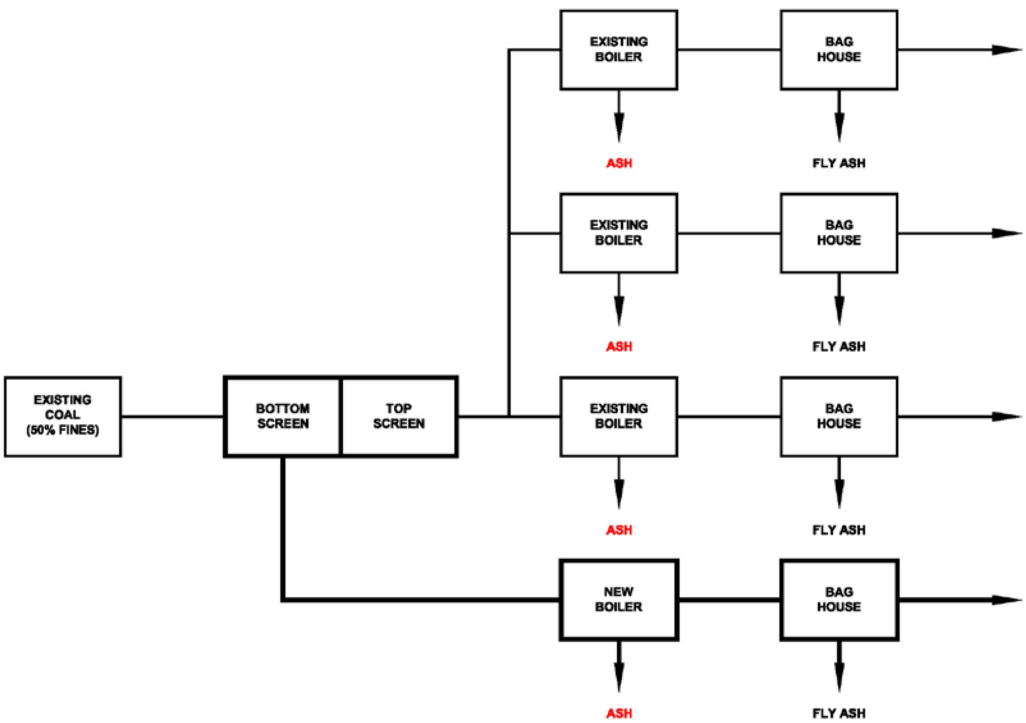
  Additional screening can be achieved by using separator screens to separate stoker grade coal from coal fines. Some examples of these separator screens are illustrated below in Figure IV-A-6 and Figure IV-A-7:

Figure IV-A-6

Figure IV-A-7

The use of separator screens will provide two streams of coal feed. The existing boilers will be fed stoker grade coal per their original design. The coal fines will be separated and can be re-processed back to the mine, sold to a third party such as Mountain Cement, or fed to an auxiliary pulverized coal burner or boiler as illustrated below:

Figure IV-A-8



- Coal Fired Steam Generation Options:

  The major problem with the present efficient and well operated coal Plant is the coal being utilized. The CEP was not designed to operate with the high quantity of fines present in the coal received.

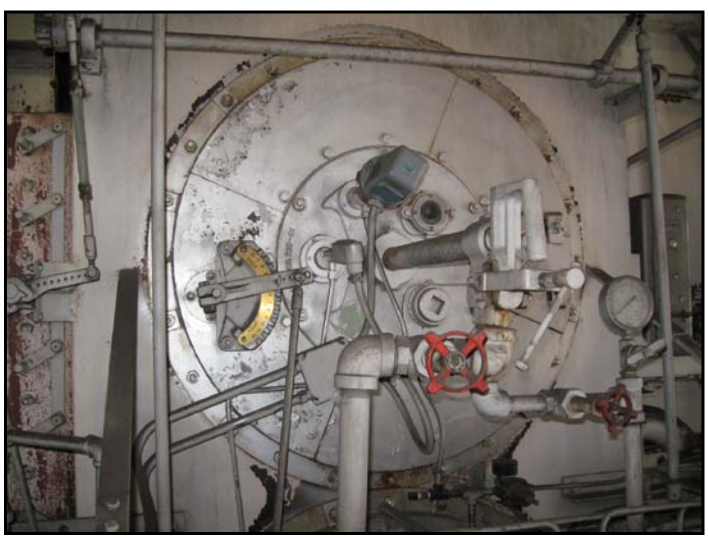
  The first Generation Option No. 1 would be to procure coal in accordance with the UW coal specification. A detailed market search within the state of Wyoming as well as adjacent states should be initiated. Recently the UW acquired a coal contract for stoker grade coal. By utilization of this stoker grade coal operational efficiencies have increased at the plant.

  The second Generation Option No. 1A would be to utilize the existing coal and or multiple sources of fuel including woody biomass and install additional equipment to support efficient operation with the poor quality coal or coal biomass mix.

b) Natural Gas Conversion (Generation Option No. 2)

The conversion to burn all natural gas is straight forward. The existing coal handling and ash handling equipment would be decommissioned and demolished. Minor breeching modifications would be required to bypass the existing baghouse. The existing natural gas and No. 2 fuel oil side-burners on Boiler Nos. 2 through 4 are nearly 30 years old and are considered to be beyond their remaining useful life as illustrated in the photograph below and should be replaced if natural gas were to become the primary fuel for the plant.

Figure IV-A-9



Boiler Nos. 2 through 4 can generate 60,000 pounds per hour (PPH) of steam when firing natural gas or No. 2 fuel oil; and Boiler No. 1 can generate 30,000 PPH of steam utilizing natural gas or

No. 2 fuel oil. According to UW personnel, Boiler No. 1 is in good condition based on its limited use over the years. Boiler No. 1 is primarily used as a backup steam generator and currently meets the UW Firm Capacity requirements under this Option.

c) Biomass Conversion (Generation Option Nos. 3, 4, & 5)

The use of biomass as a boiler fuel is expanding because of the negligible carbon footprint associated with this energy source.

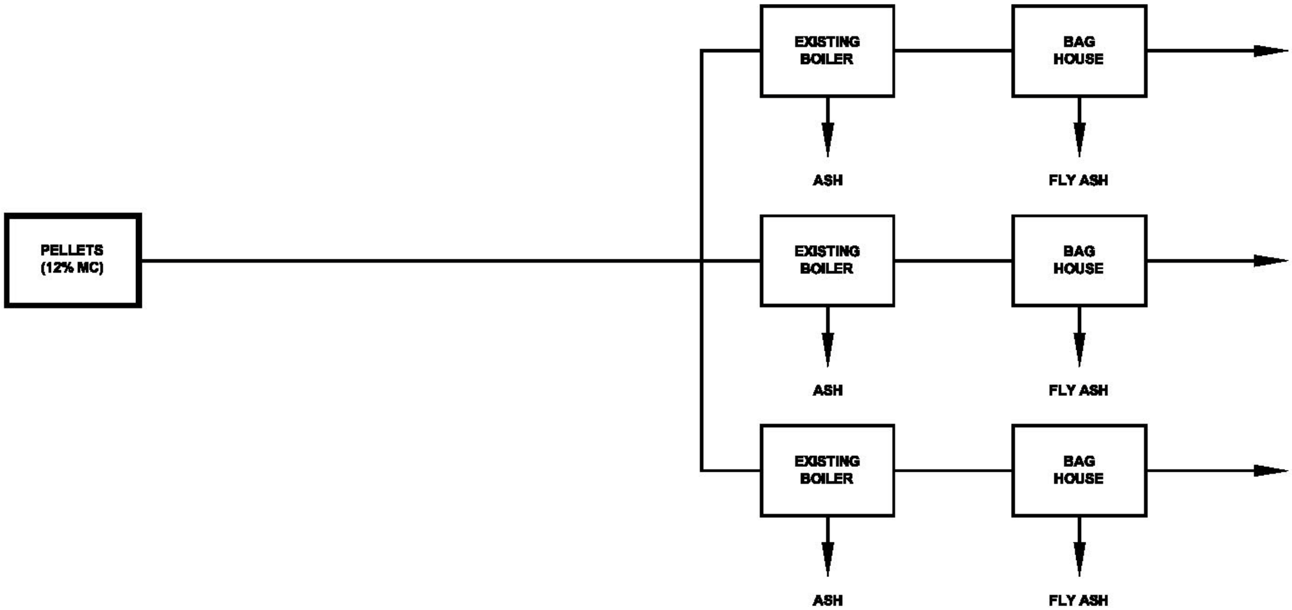
The western portions of the United States and Canada are experiencing the loss of lodgepole pine trees due to the infestation of the pine beetle. It is estimated that all lodgepole pine trees will be lost in North America within the next twenty years. Presently, the lodge pole pine residue is being manufactured into chips, pucks, and shredded mulch for residential, commercial, and industrial fuel.

The major criteria in the handling and subsequent combustion of biomass is the moisture content of the material. The greater the moisture content, the lower the heating value of the fuel and the greater boiler furnace volume required.

The existing coal boilers are capable of burning biomass with very few modifications required. In addition, the existing coal handling system has the capability to store and distribute two solid fuel sources.

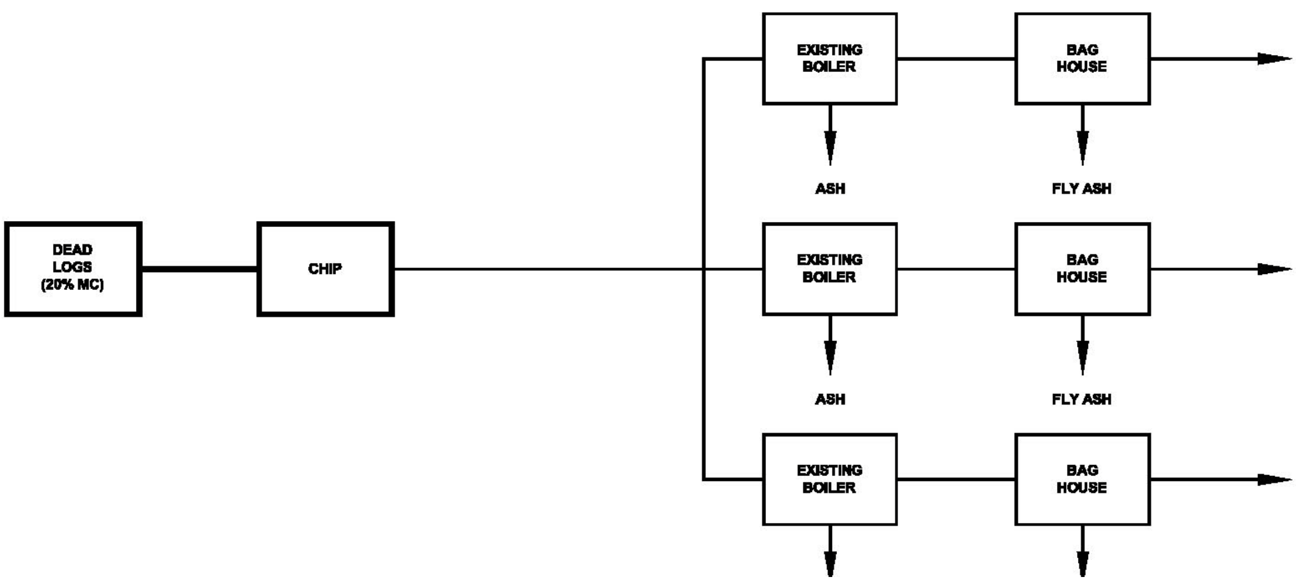
The first option for burning biomass (Generation Option No. 3) includes the use of wood pellets with a moisture content of approximately 12%. See illustration below :

Figure IV-A-10



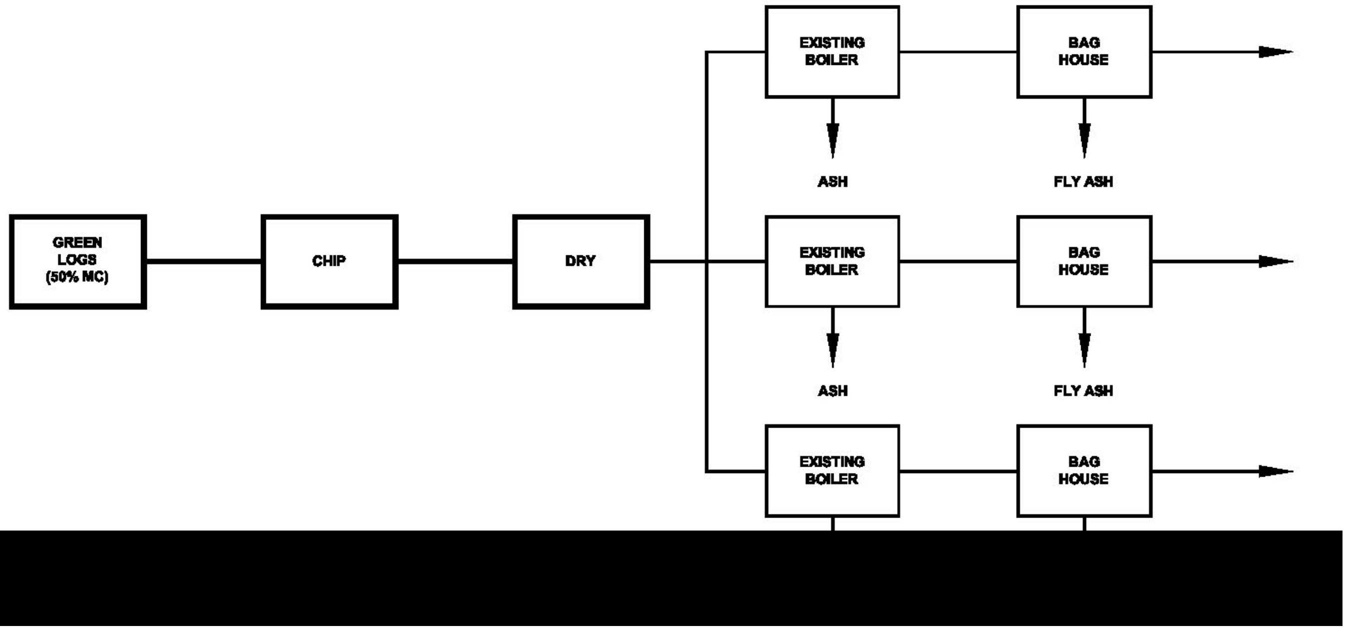
The second option for burning biomass (Generation Option No. 4) includes the use of dead (dry) logs with a moisture content of approximately 20%. This option would include the installation of a biomass prep-yard on site at the CEP and is illustrated below:

Figure IV-A-11



The third option for burning biomass (Generation Option No. 5) includes the use of green (wet) logs with a moisture content of approximately 50%. This option would include the installation of a biomass prep-yard with drying equipment on site at the CEP and is illustrated below:

Figure IV-A-12



The UW conducted a test burn of a biomass wood pellet product in one of the coal boilers on July 14, 2009. The test was conducted over approximately a six-hour period where approximately 10 tons of wood pellets were burned. The wood pellets were delivered by truck and dropped into the existing grizzly grate truck drop where it was pneumatically conveyed directly to one empty coal bunker.

During the test burn, the boiler grate speed was slowed to a minimum, the stoker rotor speed was adjusted to reduce the throw-length of the pellets into the furnace, undergrate and overfire air were adjusted, and the stoker feeders were left in automatic to maintain 125 psig saturated steam pressure to the campus. The campus load ranged from 12,000 to 19,000 PPH at the time of the test burn, and the test boiler was the only unit on line at this time.

According to UW personnel, the wood pellets appeared to have been thrown a further distance in the furnace than coal and appeared to burn "faster" than coal. The result was a vigorous, bright flame towards the rear wall only covering approximately 75% of the grate area.

Due to the abbreviated nature of the test burn conducted, the results at this time are inconclusive. RI recommends that the UW conduct an extended wood pellet test burn over several days, a full week if possible, when the campus has a significant load. Ideally, one coal boiler will be in operation during the test burn in automatic mode while the wood pellet boiler is placed in manual mode. This operational setup will allow the test boiler to be run from minimum load to maximum load manually while making required adjustments. The minimum and maximum loads will be determined at the time of the test which will yield the operational limits of the existing boilers while burning the wood pellet biomass product. It is likely that the existing boilers will be de-rated on wood pellets given the lower BTU/lb value of the biofuel verses coal. Based on the UW log data and observation notes taken from the initial test burn, RI has the following recommendations:

- Prior to conducting test burn, internally inspect existing boiler grates for clogged air passages. Punch out/clean air passages to ensure proper free flow of undergrate air.

- Place test burn boiler in manual mode, and operate boiler from minimum load to maximum load during heating season with a significant campus load.

- Introduce approximately a 10% wood pellet to coal mixture to start test burn gradually increasing to 100% biomass.

- To increase ash bed thickness, try to slow grate speed to a minimum (This was conducted by the UW).

- To increase ash bed thickness, increase stoker feeder rate to add more fuel. Wood pellets have lower ash content than coal and require a larger volume of fuel to maintain bed thickness.

- To maintain proper throw of the wood pellets into the furnace, adjust stoker rotors to achieve even distribution of fuel over entire grate area (This was conducted by the UW).

- Adjust (reduce) undergrate and overfire air to a minimum to reduce the highly vigorous and bright flame conditions experienced during first test burn. Do not reduce air flow to the point of a “lazy flame” condition. Undergrate air flow must be sufficient for proper combustion of the fuel as well as cooling of the grates.

- All adjustments should be logged in great detail throughout the duration of the test burn as each setting may be slightly different at differing boiler loads.

- New stoker technology exists equipped with finer tuning bias and turndown capable of handling a wider range of coal quality and wood pellet biomass.

A summary of the wood pellet analysis from 2006 made available by the UW is presented below.

Table IV-A-2

TABLE-IV-A-2 - WOOD PELLET BIOFUEL ANALYSIS		
SHORT PROXIMATE ANALYSIS		
DESCRIPTION	AS RECEIVED	DRY BASIS
% MOISTURE	13.35	xxxxx
% ASH	8.80	10.16
BTU/LB	10,453	12,064
%SULFUR	0.39	0.45
ALKALIES AS SODIUM OXIDE	0.09	0.11
FUSION TEMPERATURE OF ASH, °F		
DESCRIPTION	REDUCING	OXIDIZING
INITIAL DEFORMATION (IT)	2,180	2,340
SOFTENING (ST)	2,300	2,380
HEMISPHERICAL (HT)	2,330	2,420
FLUID (FT)	2,400	2,560
% WEIGHT IGNITED BASIS		
SILICON DIOXIDE	51.52	
ALUMINUM OXIDE	22.76	
TITANIUM DIOXIDE	0.91	
IRON OXIDE	7.32	
CALCIUM OXIDE	7.34	
MAGNESIUM OXIDE	1.67	
POTASSIUM OXIDE	0.33	
SODIUM OXIDE	0.75	
SULFUR TRIOXIDE	4.67	
PHOSPHORUS PENTOXIDE	1.93	
STRONTIUM OXIDE	0.35	
BARIUM OXIDE	0.42	
MANGANESE OXIDE	0.03	
UNDETERMINED	0.00	
MISC ASH CHARACTERISTICS		
TYPE OF ASH	LIGNITIC	
FOULING INDEX	0.88	
SLAGGING INDEX (°F)	2,343	
SILICA VALUE	75.93	
BASE: ACID RATIO	0.23	
T_{250} TEMPERATURE (°F)	2,666	
% AIR DRY LOSS	5.06	
MOISTURE, ASH-FREE BTU	13,428	
POUNDS OF SO_2 PER 10^6 BTU	0.75	
POUNDS OF SULFUR PER 10^6 BTU	0.37	
POUNDS OF ASH PER 10^6 BTU	8.42	

d) Fuel Option Comparison

A summary of the steam generation capacity under each option is presented below.

Table IV-A-3

TABLE-IV-A-3 - FUTURE CENTRAL ENERGY PLANT CAPACITY SUMMARY										
			EXISTING BOILERS							
OPT. NO.	DESCRIPTION	PRIMARY FUEL	BOILER NO. 1 (PPH)	BOILER NO. 2 (PPH)	BOILER NO. 3 (PPH)	BOILER NO. 4 (PPH)	FUTURE BOILER NO. 5 (PPH)	FUTURE BOILER NO. 6 (PPH)	TOTAL CAPACITY (PPH)	FIRM CAPACITY (PPH)
1	UPGRADED OPERATION	NEW COAL	30,000	60,000	60,000	60,000	---	---	210,000	150,000
1A	UPGRADED OPERATION	EXIST. COAL	30,000	60,000	60,000	60,000	60,000	---	270,000	210,000
2	EXISTING OPERATION	NAT. GAS	30,000	60,000	60,000	60,000	---	---	210,000	150,000
3	BIOMASS - PELLETS	WOOD	30,000	48,000	48,000	48,000	30,000	---	204,000	156,000
4	BIOMASS - DEAD LOGS	WOOD	30,000	40,000	40,000	40,000	40,000	---	190,000	150,000
5	BIOMASS - GREEN LOGS	WOOD	30,000	30,000	30,000	30,000	30,000	30,000	180,000	150,000

The firm capacity is the total capacity minus the largest boiler capacity. The firm capacity should be sufficient to serve the peak load of the campus (119,000 PPH).

Option No 1 applies to equipment that is implemented to burn new fuel sources including a percent mixture of coal and biomass. The percentage applied start at 10% biomass and would be tested for all mixtures for proper operations.

Under Option No. 1A, the coal will be separated between stoker grade and coal fines. The existing boilers are designed to burn stoker grade coal only. To burn the coal fines a new auxiliary boiler is required. It is recommended to install a 60,000 PPH unit to satisfy the peak load in combination with one existing coal boiler.

Under Option Nos. 3, 4, and 5 new boiler capacity is recommended to have an equivalent firm capacity of the existing boilers burning coal. The initial cost for each option is listed in table IV-A-4 below.

Table IV-A-4

TABLE-IV-A-4 - OPTIONS ANALYSIS UPGRADE COSTS							
NEW EQUIPMENT	COST ($)	OPTION 1 ($)	OPTION 1A ($)	OPTION 2 ($)	OPTION 3 ($)	OPTION 4 ($)	OPTION 5 ($)
NEW STOKERS	900,000	●	●		●	●	●
NEW DRAG-CHAIN CONVEYOR	70,000	●	●		●	●	●
NEW SCREEN SEPARATOR	270,000		●				
COVER COAL DROP	40,000	●	●		●	●	●
MECHANICAL EXHAUSTER	225,000	●	●		●	●	●
AUXILIARY COAL BOILER (60,000 PPH)	12,000,000		●				
AUXILIARY BIO-MASS BOILER (40,000 PPH)	10,000,000					●	
AUXILIARY BIO-MASS BOILER (30,000 PPH)	7,400,000				●		
AUXILIARY BIO-MASS BOILERS (2@30,000 PPH)	16,400,000						●
NEW NATURAL GAS SIDE BURNERS	2,400,000			●			
NEW PULVERIZED COAL CONVEYING EQUIPMENT	1,000,000		●				
NEW ASH SILO (SEPARATE FLY/BOTTOM ASH)	500,000		●				
NEW BIOMASS PREP YARD WITHOUT DRYER	2,200,000					●	
NEW BIOMASS PREP YARD WITH DRYER	3,100,000						●
TOTAL OPTION COST		1,235,000	15,005,000	2,400,000	8,635,000	13,435,000	20,735,000

A life cycle cost analysis of the various approaches was developed to economically compare the options. A summary of the life cycle cost is presented below in Table IV-A-5.

Table IV-A-5

TABLE-IV-A-5 - FUEL USAGE LIFE CYCLE COST COMPARISON									
				OPERATING COST					
OPT. NO.	DESCRIPTION	PRIMARY FUEL	INITIAL COST ($)	ANNUAL FUEL ($/YR)	OPER & MAINT. ($/YR)	TOTAL COST ($/YR)	PRESENT VALUE ($)	TOTAL PRESENT VALUE ($)	PRIORITY
1	UPGRADED OPERATION	NEW COAL	1,235,000	1,296,000	525,000	1,821,000	23,272,380	24,507,380	1
1A	UPGRADED OPERATION	EXIST. COAL	15,005,000	1,296,000	525,000	1,821,000	23,272,380	38,277,380	2
2	EXISTING OPERATION	NAT. GAS	2,400,000	3,644,000	315,000	3,959,000	50,596,020	52,996,020	4
3	BIOMASS - PELLETS	WOOD	8,635,000	4,199,000	682,500	4,881,500	62,385,570	71,020,570	5
4	BIOMASS - DEAD LOGS	WOOD	13,435,000	2,051,000	1,002,500	3,053,500	39,023,730	52,458,730	3
5	BIOMASS - GREEN LOGS	WOOD	20,735,000	3,137,000	1,002,500	4,139,500	52,902,810	73,637,810	6

NOTE: PRESENT VALUE FACTOR OF 12.78 IS BASED UPON 25 YEARS AT 6%

The present value of the annual fuel cost and the operation and maintenance cost for the various options was added to the initial cost to develop the total present value. The option with the lowest total present value is considered the most cost effective approach.

Option No. 1 is the most cost effective option. This option utilizes the existing boilers with a new stoker grade coal fuel source.

The cost of the new coal supply and ash disposal could increase from $55 per US ton to $90 per US ton and remain the most cost effective option.

3. Initial Heating and Power Systems, Evaluation, Economics, and Phasing Analysis

The present low cost of electricity at the UW limits the possibilities for on-site electric generation.

The use of combined heat and power also known as cogeneration was analyzed utilizing combustion turbines as well as steam turbogenerators.

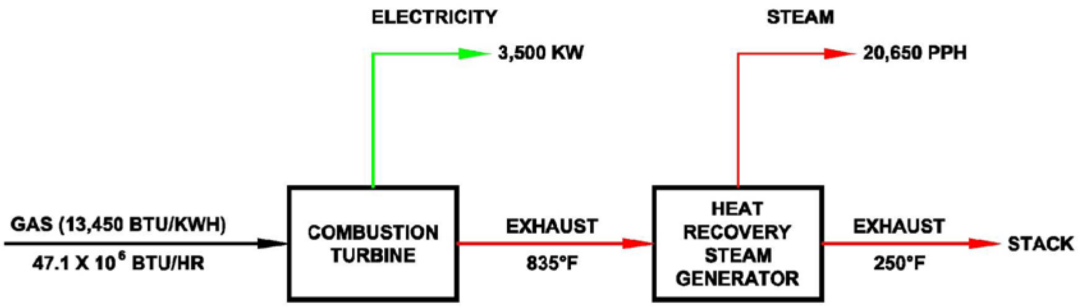
a) Combustion Turbine Analysis

The implementation of a combined heat and power system utilizing a combustion turbine as a prime mover was evaluated based upon a preliminary screening analysis.

The use of a combustion turbine cogeneration system is not cost effective. The following diagram summarizes the preliminary analysis.

Figure IV-A-13

FIGURE-IV-A-13 – CHP System (Gas-Based Steam Offset)



Fuel In = 47.1×10^6 Btu/Hr

Electric Output = 3,500 kW = 11.95×10^6 Btu/Hr

Steam Output = 20,650 PPH = 20.65×10^6 Btu/Hr

Efficiency Without HRSG = 11.95/47.10 = 25.4%

Efficiency With HRSG = (11.95 + 20.65)/47.10
= **69.2%**

Typical Utility Company Efficiency = **33%**

Electric Cost = $0.055 / kWH
Natural Gas Cost = $7.20 / Decatherm
Existing Boiler Eff = 80%
Steam = 1,000 Btu / pound
System Availability = 95%

Revenues:	Electric	$1,632,000 / yr	
	Steam	$1,505,000 / yr	
	Total	**$3,137,000 / yr**	
Costs:	Nat. Gas	($2,808,000 / yr)	
	O&M	($ 223,000 / yr)	
	Total	**($3,031,000 / yr)**	
Annual Savings:			**$106,000 / yr**
Project Cost:			**$7,000,000**
Simple Payback:			**> 25 years**

Regional Carbon Dioxide Reduction = 13,880 Tons / Yr

b) Back Pressure Turbine Analysis

The use of a backpressure steam turbogenerator is a form of combined heat and power.

From the steam load duration curve, the minimum steam demand throughout the year is 20,000 PPH. The existing maximum working pressure of the plant is 250 psig. Modifications to the plant would be required to increase the existing generating pressure to 250 psig.

Various generalized steam flow models were developed.

- 20,000 PPH - 42% of all steam produced
- 40,000 PPH – 74% of all steam produced
- 60,000 PPH – 93% of all steam exported

The following table lists the turbine generator operating characteristics for the various steam flow scenarios.

Figure IV-A-14

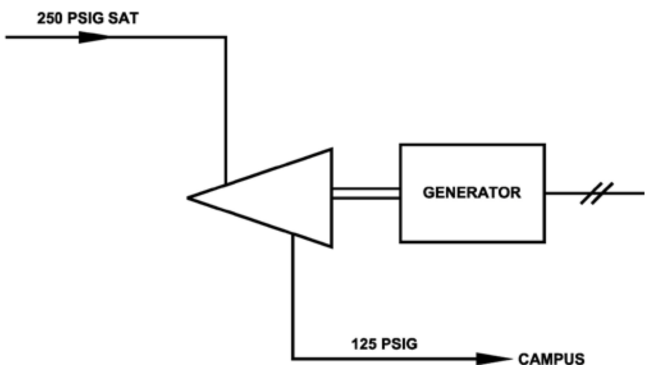


TABLE-IV-A-6 - TURBOGENERATOR OPERATING CHARACTERISTICS

MAXIMUM THROTTLE FLOW (PPH)	STEAM EXHAUSTED (10^6 PPY)	ELECTRIC PRODUCTION					ADDITIONAL FUEL INPUT			
		PEAK (KW)	ANNUAL (KWH)	GROSS REVENUES ($/YR)	O&M ($/YR)	NET REVENUE ($/YR)	ANNUAL (10^6 BTU/HR)	COAL ($/YR)	GAS ($/YR)	BIOMASS ($/YR)
20,000	174	200	1,740,000	95,700	(3,500)	92,200	6,190	19,440	54,660	51,820
40,000	304	400	3,040,000	167,200	(6,100)	161,100	10,810	33,940	94,450	90,490
60,000	383	600	3,830,000	210,700	(7,700)	203,000	13,616	42,750	120,230	113,980

NOTES:
1. NET FUEL COST COAL = $3.14 / 10^6 BTU
GAS = $8.83 / 10^6 BTU
BIOMASS = $8.37 / 10^6 BTU
2. O&M COST = $0.002 / KWH

The initial cost of the various turbogenerator sizes was developed. Included is the capital cost to increase the plant generation pressure to 250 psig including new relief and feedwater valves at each boiler, and new feedwater pumps.

TABLE-IV-A-7 - INITIAL COST OF STEAM TURBOGENERATORS				
MAXIMUM THROTTLE FLOW (PPH)	GENERATOR SIZE (KW)	TURBOGENERATOR INSTALLATION ($)	BOILER PLANT MODIFICATIONS ($)	TOTAL COST ($)
20,000	200	510,000	250,000	760,000
40,000	400	830,000	250,000	1,080,000
60,000	600	1,100,000	250,000	1,350,000

The following table summarizes the life cycle present value analysis of the various steam turbogenerators.

TABLE-IV-A-8 - PRELIMINARY SUMMARY OF TURBOGENERATOR ANALYSIS									
				OPERATING SAVINGS					
FUEL	MAXIMUM THROTTLE FLOW (PPH)	GENERATOR SIZE (KW)	INITIAL COST ($)	ELECTRIC ($)	ADD FUEL ($/YR)	NET ($/YR)	PRESENT VALUE ($)	TOTAL PRESENT VALUE OF SAVINGS ($)	SIMPLE AMORITIZATION (YRS)
COAL	20,000	200	760,000	92,200	(19,400)	72,800	930,400	170,400	10.4
	40,000	400	1,080,000	161,000	(33,940)	127,060	1,623,800	543,800	8.5
	60,000	600	1,350,000	203,000	(42,750)	160,250	2,048,000	698,000	8.4
GAS	20,000	200	760,000	92,200	(54,660)	37,540	479,800	(280,200)	20.2
	40,000	400	1,080,000	161,000	(94,450)	66,550	850,500	(229,500)	16.3
	60,000	600	1,350,000	203,000	(120,230)	82,770	1,058,000	(292,000)	16.3
BIOMASS	20,000	200	760,000	92,200	(51,820)	40,380	516,000	(244,000)	18.8
	40,000	400	1,080,000	161,000	(90,490)	70,510	901,000	(179,000)	15.3
	60,000	600	1,350,000	203,000	(113,980)	89,020	1,138,000	(212,000)	15.2

The present value listed in the above table is the initial cost less the present value of the operating savings over the system life. A system life of 25 years and an interest rate of 6% result in a present value factor of 12.78. The analysis does not include fuel escalation because of the uncertainty in future fuel costs.

It can be seen from the table that the use of a backpressure steam turbogenerator utilizing coal as the boiler fuel is cost effective. The use of natural gas and biomass as the boiler fuel is not cost effective. These results do not consider the potential increase in electric cost per unit of electricity remaining due to the utility provider schedule change for onsite generated power.

To avoid an increase to the electric rate there is a potential to isolate the utilization of generated power to a specific area on campus with generator backup. This will essentially remove the produced power from campus and will isolate the system such that it does not apply to a rate change by the utility provider.

4. Carbon Sequestration

The reduction of carbon dioxide emissions is a recent area of special interest because of global warming. The removal process of carbon dioxide from combustion products is an evolving technology. Most prototype demonstration projects associated with the removal of carbon dioxide are orders of magnitude greater than the UW plant.

A recent comprehensive analysis of the coal-fired U.S. Capitol Power Plant which utilizes approximately 30,000 TPY of low sulfur semi-bituminous coal was developed. The process utilizes an amine flue gas scrubber and settling ponds in which the carbon dioxide was converted to a usable biomass. The estimated cost of the system was approximately $78 million and required an additional 20% energy input. The additional unitary cost of this carbon sequestration system over a 20-year life cycle was $230 per ton of coal. The process is not cost-effective.

Presently, there are no cost-effective methods of direct carbon sequestration applicable to the UW. As research and subsequent technology are developed, the use of carbon sequestration may become cost-effective at similar smaller scale coal-fired plants.

5. Conclusion

As stated in section IV-2-d above, Generation Option No. 1 has the lowest total present value and is considered the most cost effective approach. This option utilizes the existing boilers with a new stoker grade coal fuel source. The cost of the new coal supply and ash disposal could increase from $55 per ton to $90 per ton and still remain the most cost effective option. Based on a five year approach, this option should be considered now to bring the CEP to the year 2015 at a cost of $1,235,000.

Based upon the core campus future load growth, additional boiler capacity is required in 2019. The additional capacity recommended for 2019 corresponds with a 40-year system life of the plant. Based on a five year approach, Option No. 4 should be implemented in 2015 to prepare for the load growth occurring in 2019. This Option can be implemented at an additional cost of $12,200,000 for a 40,000 PPH future auxiliary biomass Boiler No. 5 and a biomass prep yard. Option No. 4 is the most cost effective option among the biomass alternatives. This option allows for a firm capacity of 150,000 PPH.

It is recommended that UW allow for a $30 million (2009 dollars) replacement cost for the boilers in the capital budget plan. This budgetary amount would allow for the full replacement of all heating plant equipment and auxiliaries within the existing CEP. The equipment includes boilers that would burn a solid fuel source of either coal, biomass product (dry logs or wood pellets) or a mixture of the two. Commercially available biomass sources as well as combustion technologies are currently developing and should be investigated further. Additionally, green power can be generated at an additional value of $0.008 per KWh but could increase with carbon tax.

C. Additional Systems Evaluation, Economics, and Phasing Analysis

1. Off Campus Source

a) Option A and B - Purchased Electric Renewable Energy Credits and Wind Turbine Electric Generation

- Option A- Purchasing Renewable Energy Credits

Rocky Mountain Power (RMP) offers a program called Blue Sky, which allows customers to purchase a bundle of offsets to invest in regional wind resources. When a customer enrolls in the program, RMP purchase a pre-determined amount of renewable energy credits on behalf of the customer. The credits can be purchased at $1.20 per kwh for the entire campus. The credits are third-party certified by Green E-certification to ensure proper investment of funds. Funds are allocated to build wind turbines in the region or buy other renewable energy credits. Further investigation is needed to understand whether the REC's purchased through this program can be counted as a carbon reduction on the part of UW.

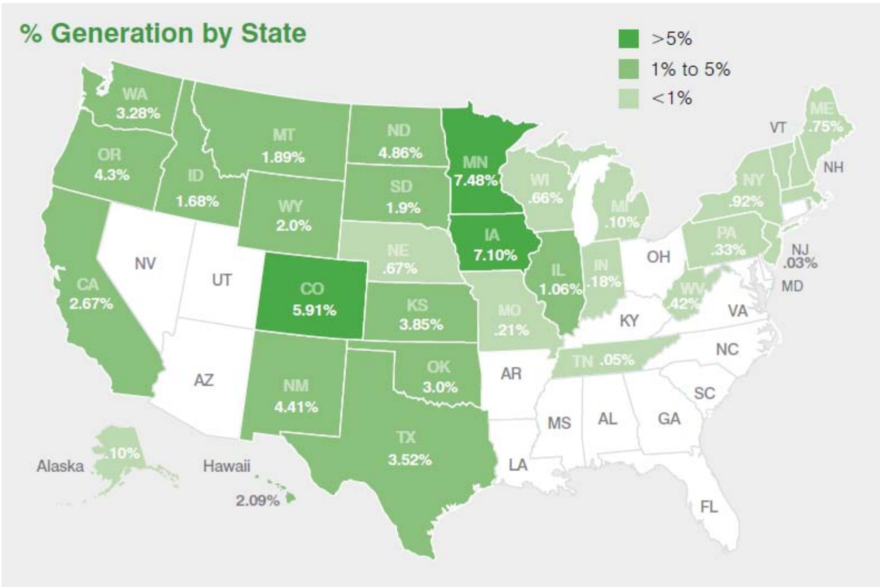
Renewable Choice Energy offers a similar program and is understood that energy credits can be purchased to offset the entire carbon production by the electric utility provider to a net zero count that is applied to the campus as a whole. These renewable credits are also Green E certified and further information on Renewable Choice Energy can be found at www.renewablechoice.com.

Renewable energy credits are a valid option for reduction of GHG emissions. Further investigation will be required to determine if the capital expenditure is necessary to reach the UW's commitment of emissions reductions to the American College and UW Presidents Climate Commitment (ACUPCC) and or internal UW goals.

- Option B- Investment in Commercial Wind Turbine

Currently, the United States is the world leader in installed capacity of wind power, with approximately 12,000 MW of capacity as of December 2008. Wyoming boasts a strong wind resource with 676 MW of wind power currently installed comprising 2% of the state's electricity generation (see figure below).

Figure IV-C-1-1



(Source: AWEA, 2008 Annual Wind Industry Report)

The UW - Laramie is advantageously situated in some of the state's prime wind resource in the southeastern part of the state (see figure below). Nearby Cheyenne has a slightly higher wind resource.

Figure IV-C-1-2

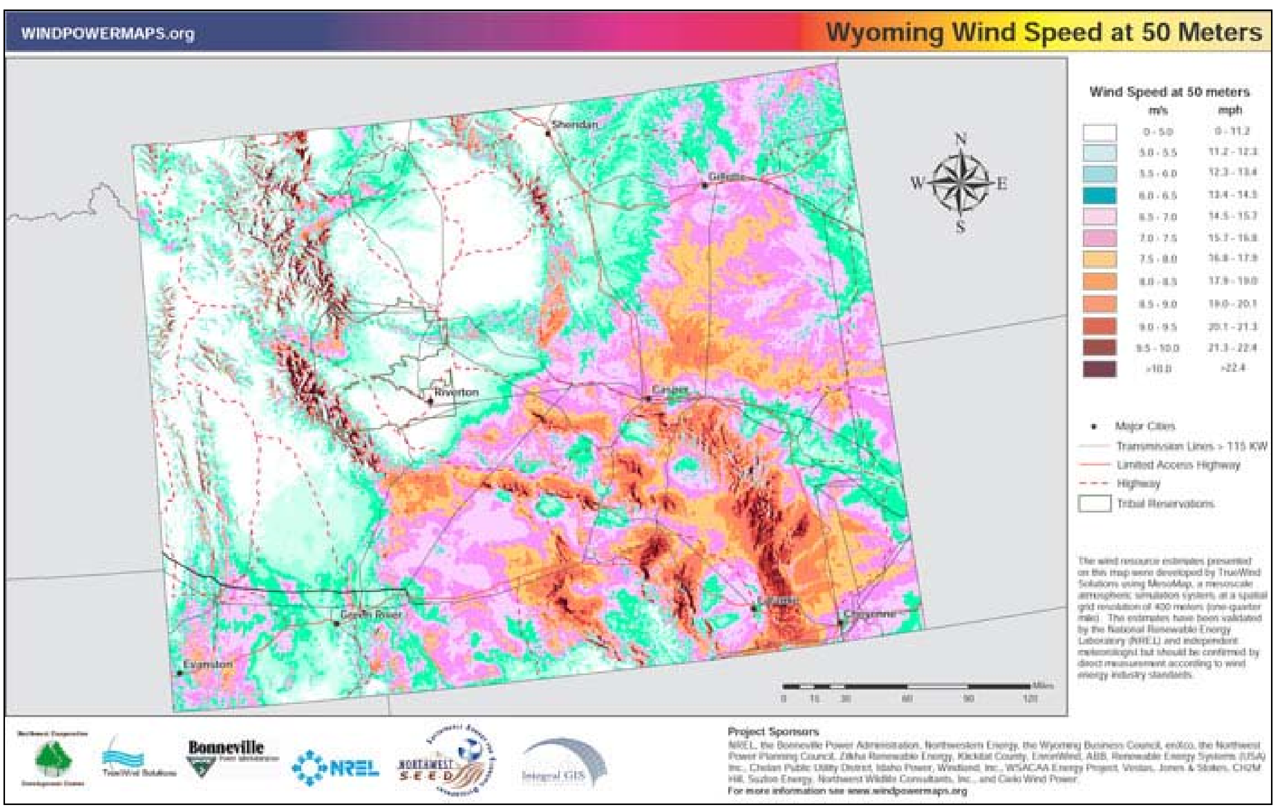
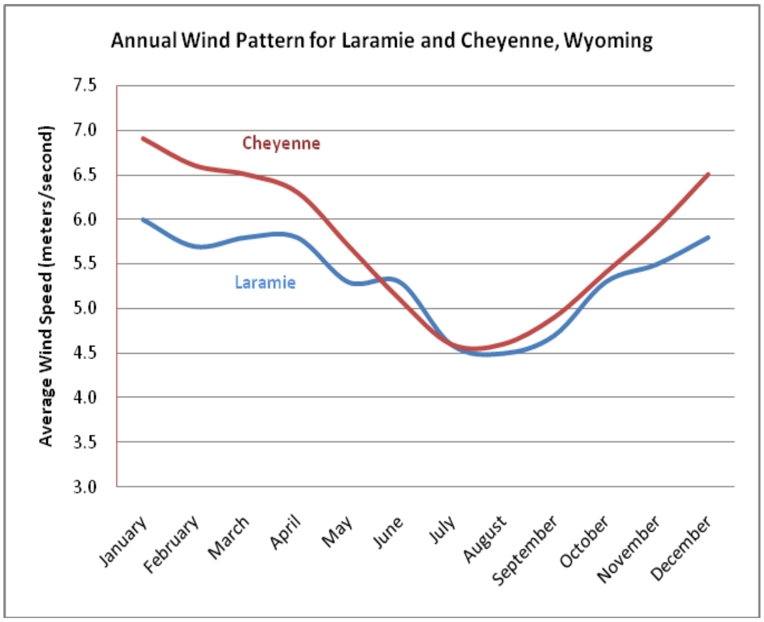
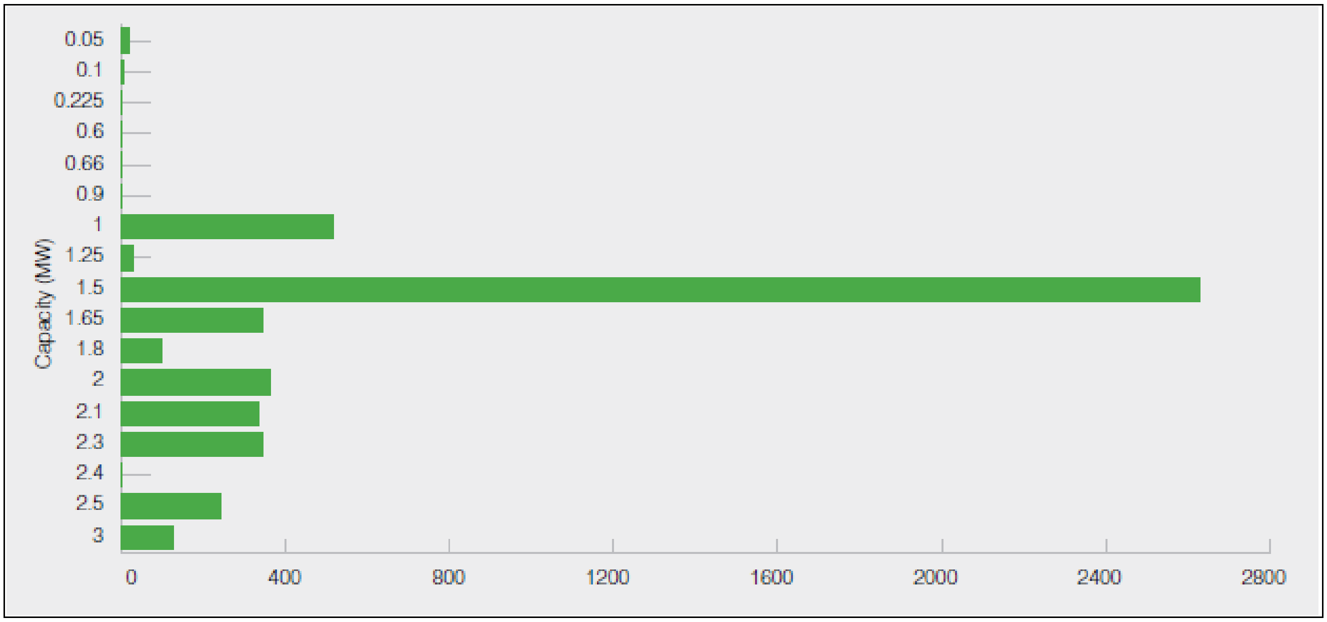


Figure IV-C-1-3



This analysis considers two options for the UW-Laramie campus to supplement their electricity production and increase their renewable energy portfolio: a 1.5 MW turbine and a 2.5 MW turbine. The most common size of commercial wind turbines today is 1.5 MW (see figure below). While currently there are turbines of up to 5 MW, they are not as commercially available as the 1.5-2.5 MW turbines.

Figure IV-C-1-4, Distribution of Turbines Installed in 2008 by Capacity



Because of the current economic environment, it should be noted that the prices used in this analysis are generalized figures and could change according to the UW's specific inquiry. The numbers provided here take a conservative approach and utilize the higher end of the range of potential costs. The current range of installed costs for is from $1,700/kW to $2,500/kW. The costs used in this analysis would decrease if more than one turbine was considered; a wind farm of over 30 turbines would likely see total installed costs closer to $1,700/kW per a conversation with an Analyst at Seventh Generation Energy, Madison, WI. The wind turbine is assumed to have a lifespan of 20 years.

Capacity factor is the ratio of actual energy produced to the hypothetical maximum amount of energy. If the wind blew all year long without stopping, the capacity factor would be 100%. However, because the wind does not always blow, capacity factors are significantly lower than conventional electricity generation. For this analysis, we assumed a capacity factor of 38%.per a conversation with the UW Physical Plant Staff. Before investing in a turbine, a more detailed site study should be undertaken to obtain a more site-specific capacity factor.

Operations and maintenance costs are assumed to be 2% of the total installed costs. O&M costs are projected to be lower in the first years of project and are expected to increase with the project life.

The Federal government currently offers a Renewable Energy Production Tax Credit (PTC) on wind energy production. The PTC offers 2.1¢/kWh until the end of 2012. Per the link below

http://dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US13F&State=federal&currentpageid=1&ee=1&re=1

If built before the 2012 deadline, the PTC can be applied for 10 years. It is uncertain whether the PTC will be extended beyond that time.

While wind resources are very good near Laramie, it should be noted that electricity prices are very low at $0.0588/kWh. When comparing electricity generated from coal to electricity generated from wind, the low prices of coal make wind less cost-competitive. Carbon prices in the future may significantly sway this analysis in wind power's favor. Because wind generation does not burn fossil fuels, wind power will be positively affected by potential policy changes to regulate carbon emissions. A carbon cap-and-trade or tax will likely raise the rates of Wyoming's coal-powered electricity, making wind energy a more competitive energy source with a shorter payback time.

Table IV-C-1-1

Laramie, WY Wind Turbine Analysis	**1.5MW Turbine**	**2.5 MW Turbine**
Assumed Installed Cost ($/KW)	$2,500	$2,200
Annual MWh Production (MWh)	5,010	8,350
Capital Cost ($)	$3.8 million	$5.5 million
Tax Credit	2.1¢/kWh	2.1¢/kWh
Equity Payback Time (See Figure IV-C-1-5 and IV-C-1-6)	13 years	10.2 years
Reduction Potential (MTCO2E annual) (1)	4,368	7,291

(1) Based on Values Indicated by Rocky Mountain Power/PacifiCorp

Figure IV-C-1-5

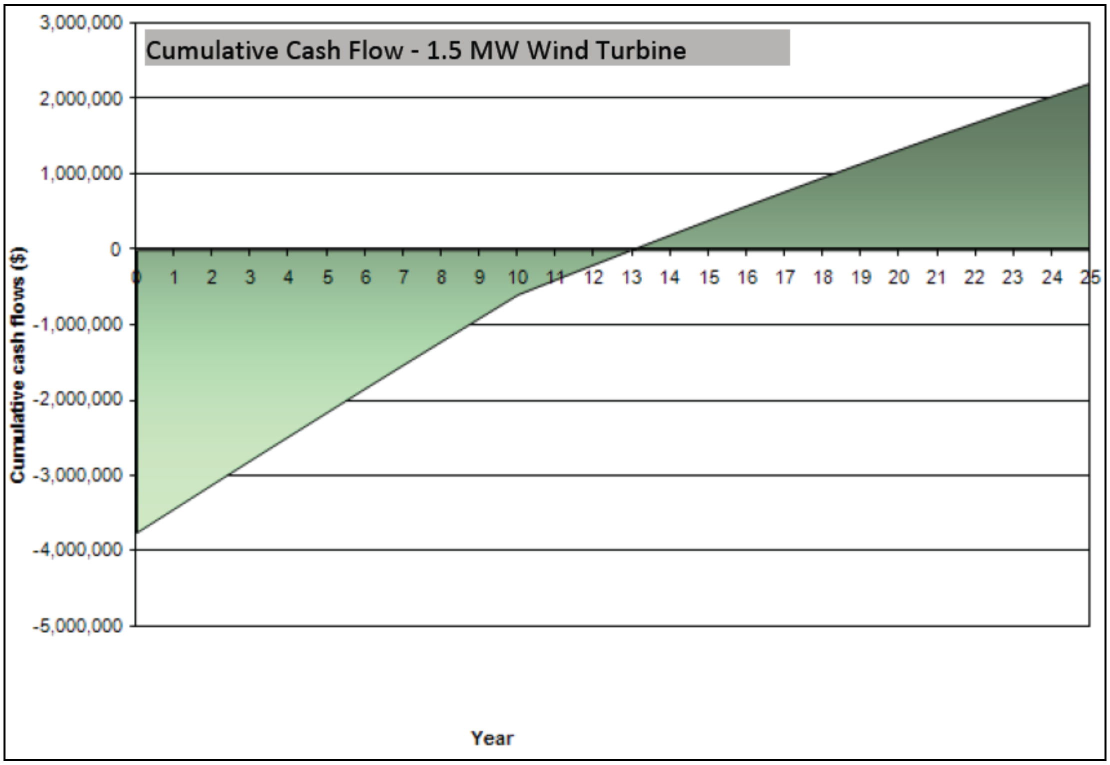
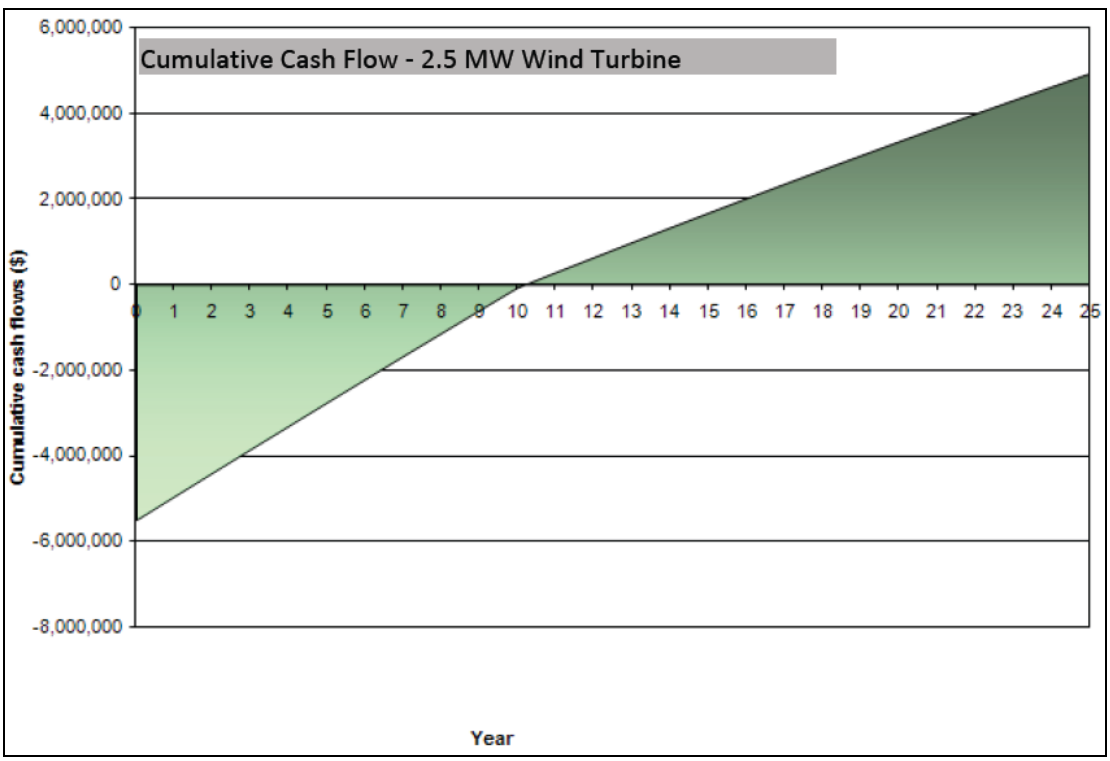
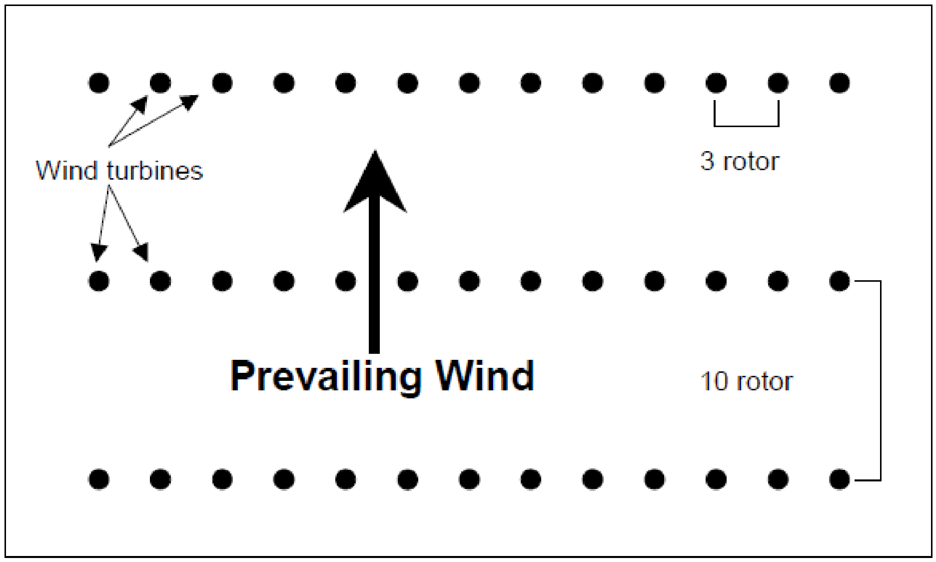


Figure IV-C-1-6



A commercial sized wind turbine should expect to have a "footprint" of approximately 0.5 acres. If more than one turbine is built, the turbines need to be spaced out with the equivalent of 3-10 rotor diameters (diameter of the blades) between each turbine. The figure below shows the optimal spacing for a large wind farm. It is generally thought that a turbine should be situated about 1 times its total height (hub height plus rotor diameter) away from the nearest road/building (based on http://www.wind.appstate.edu/reports/WindEnergyFactSheetWNCREIFeb07.pdf); however, Wyoming-specific zoning laws need to be considered.

Figure IV-C-1-7



Transmission costs should be taken into consideration when analyzing the cost-effectiveness of turbine. According to the wind speed map above, there is a transmission line running through Laramie. Depending on the site chosen to develop the wind turbine, the interconnection costs to this transmission line need to be calculated. Currently, transmission lines cost approximately $1 million/mile. The UW needs to talk with its utility for interconnection rights and queues.

2. On Campus Source

a) Option 1 –Demand Side Opportunities Existing Building Renovation and Future Green Building

AEI conducted a survey of four "typical" buildings on campus to establish a baseline towards improvements that could be applied to building operations (Controls), and systems. These improvements would increase building efficiencies that in turn reduce the demand on the campus thermal and electrical infrastructure. The four buildings evaluated were Fine Arts, Arts and Science, Physical Science and Wyoming Union.

The survey of each building control system included a review of scheduling, air handling unit control schemes, pumping strategies, terminal controls, lighting controls, and miscellaneous system controls. A summary of the survey is included in Appendix IV-C and is listed by building type 1-4 corresponding to the building surveyed.

After the survey was completed a series of recommendations were recognized that could potentially increase building system efficiencies. These recommendations are located at the end of each building survey within the Appendix.

In order to estimate the potential energy savings for the recommendations made, each was compared to savings from similar modeled buildings. The savings presented here must be recognized as estimate values only and do not have the certainty of a fully modeled building. The actual energy savings for the UW's buildings may vary (+/- 10-15%) based on building specifics such as: technology, equipment, envelope characteristics, and weather. The following steps describe the method used to estimate the UW's energy savings potential.

Step 1: Building Comparison to Energy Conservation Measures

The recommendations noted above were compared to the energy conservation measures (ECMs) from similar modeled buildings. Energy conservation measures are building retrofits and maintenance actions that reduce the buildings energy consumption without sacrificing the building's productivity. Table IV-C-2-1 identifies the UW master plan control upgrade recommendations and their corresponding ECM numbers. Descriptions of the energy conservation measures can be found in Table IV-C-2-1 within the Appendix IV-C.

Table IV-C-2-1

UW of Wyoming Recommendation	ECM Number	ECM Name
Convert CV to VAV	3	VAV Terminal Minimum Position
	6	Simultaneous Heating and Cooling Solutions
	16	Variable Frequency Drive Motor Conversion
	17	VAV Conversion
Monitor Kitchen Hood Exhaust Fan Run Status	18	VAV Fume Hoods
HVAC Scheduling (Occupancy)	1	Setback
	4	HVAC Scheduling
	14	VAV Full Shut-off
CO2 Sensors/Damper Reset	15	Outside Air Variation with CO2 Sensors
Fume Hood Tied to BAS	18	VAV Fume Hoods
Light Scheduling (Occupancy)	5	Lighting Scheduling
	12	Occupancy Sensors
Daylight Harvesting	13	Daylight Sensors
Divide Meeting Room into 3 Zones	n/a*	n/a
Miscellaneous Fountain Timer, Pumps, and Lights	n/a*	n/a
DDC Installation	Included **	Included

* The savings from these recommendations are minor compared to the total building energy demand and were labeled unique outliers.

** The ECMs for variable air volume (VAV) conversion include the energy savings realized from the installation of a DDC system. Therefore, DDC savings are included in ECMs 1, 3, 8, 15, 17, and 22.

Step 2: Determine Results by Comparing Similar Modeling Results.

The first set of columns titled "Demand Reduction by Utility" shows the total reduction in electrical, chilled water, and steam demand for each set of ECMs. The second set of columns titled "Building Demand Reduction" applies the utility distribution weight to the "Demand Reduction by Utility" and shows the building's total demand reduction. For Building Type 1, the demand for electricity decreases 27% but that reduction only represents 8% of the building's total energy consumption.

Tables IV-C-2-2, thru 5 includes values from the model comparison for the four "typical" building types surveyed.

Table IV-C-2-2 Building Type 1, Wyoming Union

Recommendation	ECM #	Demand Reduction by Utility			Building Demand Reduction		
HVAC		Electricity	CHW	STEAM	Electricity	CHW	STEAM
Convert CV to VAV	16, 17, 6, 3	7%	21%	23%	2%	8%	7%
Replace Pneumatic w/ DDC	included						
Monitor Kitchen Hood Exhaust Fan Run Status	18	12%	21%	21%	3%	8%	7%
Scheduling (Occupancy)	1, 4, 14	8%	10%	20%	2%	4%	6%
Divide Zones	unique						
CO2 Sensors	15	1%	3%	3%	0%	1%	1%
Hydronic Systems							
CV HHW to VV	included						
Convert Steam Controls to DDC	included						
Total		27%	55%	66%	8%	22%	22%
Total Bldg Savings							**51%**

Table IV-C-2-3 Building Type 2, Physical Sciences

Recommendation	ECM #	Demand Reduction by Utility			Building Demand Reduction		
HVAC		Electricity	CHW	STEAM	Electricity	CHW	STEAM
Replace CAV w/ VAV Supply and Exhaust	16, 17, 6, 3	7%	21%	23%	2%	8%	7%
CO2 Sensors/ Damper Reset	15	1%	3%	3%	0%	1%	1%
Replace Pneumatic Controls	included						
Scheduling/Occupancy Sensors	1, 4, 14	8%	10%	20%	2%	4%	6%
Fume Hood/Space Exhaust Req Adjusted, Tied to BAS	18	12%	21%	21%	3%	8%	7%
Hydronic Systems							
CV HHW to VV	included						
Lighting							
Occupancy Sensors	5, 12	2%	2%	0%	0%	1%	0%
Daylight Havesting	13	4%	2%	0%	1%	1%	0%
Total		33%	58%	67%	9%	23%	22%
Total Bldg Savings							**54%**

Table V-C-2-4 Building Type 3, Fine Arts

Recommendation	ECM #	Demand Reduction by Utility			Building Demand Reduction		
AHU		Electricity	CHW	STEAM	Electricity	CHW	STEAM
Replace Pneumatic w/ DDC							
Convert Air to VAV	16, 17, 6, 3	7%	21%	23%	2%	8%	7%
Occupancy Schedule	1, 4, 14	8%	10%	20%	2%	4%	6%
CO2 Sensors and Resets	15	1%	3%	3%	0%	1%	1%
Fume Hoods Tied to BAS	18	12%	21%	21%	3%	8%	7%
Hydronic Systems							
Convert HHW CV to VV							
Lighting							
Occupancy Sensors	5, 12	2%	2%	0%	0%	1%	0%
Daylighting/Dimming	13	4%	2%	0%	1%	1%	0%
Misc							
Fountain Timer	unique						
Pumps	unique						
Lights	unique						
Total		33%	58%	67%	9%	23%	22%
Total Bldg Savings							**54%**

Table IV-C-2-5 Building Type 4, Arts and Sciences

Recommendation	ECM #	Demand Reduction by Utility			Building Demand Reduction		
HVAC		Electricity	CHW	STEAM	Electricity	CHW	STEAM
Pneumatic to DDC	included						
Occupancy Sensor	1, 4, 14	8%	10%	20%	2%	4%	6%
Lighting							
Occupancy Sensor	5, 12	2%	2%	0%	0%	1%	0%
Daylighting/Dimming	13	4%	2%	0%	1%	1%	0%
Total		14%	13%	20%	4%	5%	6%
Total Bldg Savings							**16%**

In order to evaluate the vast array of buildings on campus to understand net potential energy savings, the values of building demand reductions were incorporated into Table IV-C-2-6 within Appendix IV-C. This spreadsheet evaluates the total % savings by comparing the existing buildings and type to the building type and building demand reduction values estimated above. Building type comparisons were provided by UW Staff to reduce extensive survey of each building on campus.

After all input was complete new diversified numbers were produced from the estimated savings, a new campus total was produced, and a net energy savings based on campus existing loads was produced as highlighted in cyan and red within the table. These numbers were then used within the evaluation as a total % savings for the campus as a whole and assumed per building. This direction was taken since there is not an understanding of timeframes that each existing building (corresponding to building type 1-4) may potentially undergo a control upgrade. The total campus numbers were also utilized within section IV-E to evaluate decrease of emissions for the demand side reduction of purchased electric and fossil fuel use on campus.

Preliminary estimates of each building type were also performed to understand the potential cost of the total campus upgrades. The method taken is similar to the energy savings indicated above and produces an estimated campus cost that can be used as a base for multiple years of upgrades. Estimates were performed for each building type 1-4 to produce a dollar per square foot that could be applied to the similar buildings on campus. The estimates were produced by comparing the recommendations made to corresponding equipment in each survey that would require an upgrade. Smaller more finite equipment/upgrade estimates and details were utilized to get an overall value to each building and then divided into the building SQFT to obtain the value. Each building estimate is included within their respective building survey and recommendations section within Appendix IV-C. Each detailed equipment/upgrade estimate and a summary of Building Type $/SQFT are included in Appendix IV-C.

A simple cost savings analysis was then performed based on the average full campus savings and average full campus savings with +15% tolerances added. The capital cost for the estimated full campus cost was spread over 9 years of upgrade completion with 25% in the immediate 3 years and the remaining 75% in the following six years. The simple present year cost savings for the average percent savings is presented in Table IV-C-2-7 and Table IV-C-2-8 within the Appendix which includes a summary table of savings and the cost savings estimates based on year 2008 fossil fuel cost.

The evaluations performed above are schematic in nature and were performed to gain a sense of potential that demand side opportunities could benefit the campus. If more defined values are required it is recommended that detailed survey an modeling of each building take place to determine the actual savings the campus is going to see.

3. Summary

- Wind Power Generation and Renewable Energy Credits

Wind Generated Power is currently not desired to be owned and operated by the Physical Plant Staff and there was recent mention of the lack of applicable property that a wind farm could be placed due to other environmental and wildlife concerns. The rather large capital required to build a recognizable renewable electric source for the campus would need to be considered this year by the UW in order to gain the incentive noted. Wind Generated Power should not be considered at this time.

There may be a need to address wind generated power in the future as this could lead to reduction of high CO2 content utility provided electricity/Campus carbon footprint and avoid a potential carbon tax currently being investigated within Federal Government. To potentially avoid the large capital cost and operation and maintenance cost for wind the UW should consider purchasing Renewable Energy Credits which accomplish reductions to GHG emissions in their entirety to the campus similar to wind. Further evaluation of multiple firms for these credits and cost per the UW electric system will be required.

- Demand Side Opportunities

The building survey and recommendation performed for each building type provides an initial sense of upgrades that can be implemented to gain the demand side energy savings. However, is not detailed to the extent required to provide a priority of upgrades and cost to implement other than the estimates provided. It is recommended that each building's systems and controls be extensively surveyed and documented by consulting firms that specialize in this field for proper design and implement of the upgrades.

Although the campus savings compared to initial capital cost are low, the demand side energy reductions above are anticipated to be closer to +15% tolerances or more with upgrades to the building operations, equipment, and systems.

Capital placed toward control and equipment upgrades is recommended for buildings that are currently not operating through up to date technology and controls that have the ability for advanced scheduling and building energy optimization. If technology is current and controls optimization not implemented, capital should be provided to review the upgrades necessary and revise the controls system to maximize the building energy reduction

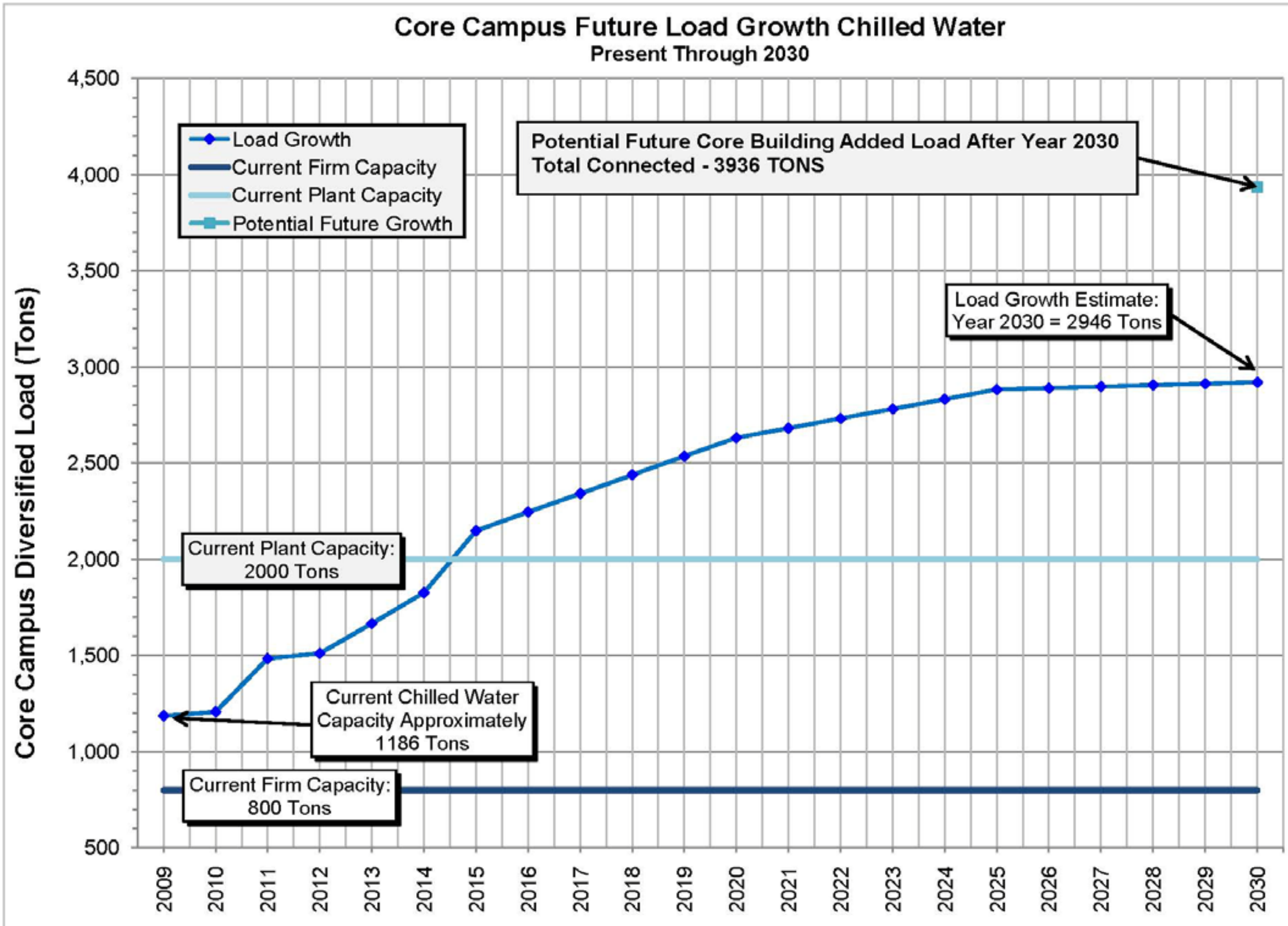
The energy reductions will also contribute to yearly reduction of fossil fuel for heat generation and utility provided electricity. In turn the reductions are applied directly to emissions reductions committed to by the UW within the American College and UW Presidents Climate Commitment (ACUPCC). Demand side energy reductions are evaluated further within Section IV-E of this report to recognize the potential emissions reductions.

D. Chilled Water System

1. Initial Options Evaluation, Economics, and Phasing Analysis

Currently the campus chilled water system firm capacity is 800 tons. Required firm capacity is approximately 1200 tons per estimates and UW input. If the 1200 ton chiller were to fail or is shut down for maintenance the campus would experience a shortage of cooling capacity during the peak cooling season seen by the campus. In addition the system should be upgraded as required per the projected load growth in the 20 year timeframe indicated in Figure III-C-1 below (from Section III). New chilled water capacity and additions will range in value from approximately $2,000 to $3,500 dollars per ton of capacity pending the auxiliaries and fit out performed.

Figure III-C-1



Utility distribution has been evaluated in Section III and is adequate to sustain additional load up to 2500 tons within the 14” pipe immediately from the CEP. This capacity is based on a 14° delta and maximum pipe velocity of 10fps. Additional information can be found in Table IV-D-1 for evaluation of future loads through pipes in comparison to delta T of the chilled water system.

Projected growth area A north of Lewis and potential existing west core campus conversions will add a significant chilled water load to the west of campus. There may be significant upgrades required around 2020 that would impede on the useful operating life of new equipment (30 years pending maintenance) if the capacity is added at the CEP. There is new utility piping cost also associated that would range approximately $45-$50 per inch per ft of pipe which includes material, excavation and installation

Table IV-D-1

CHILLED WATER COILS SELECTED FOR 14-16 DEGREE F TEMPERATURE DIFFERENTIAL					
CHILLED WATER PIPE SIZE NOMINAL DIAMETER (INCHES)	RECOMMENDED FLOW RANGE		CHILLED WATER DELTA TEMP. (DEG F)	LOW TON RANGE (TONS)	HIGH TON RANGE (TONS)
	LOW (1)	HIGH (2)			
4	130	270	14	76	158
6	500	800	14	292	467
8	800	1500	14	467	875
10	1500	2100	14	875	1225
12	2100	3200	14	1225	1867
14	3200	4300	14	1867	2508
16	4300	5900	14	2508	3442
18	5900	7000	14	3442	4083
CHILLED WATER COILS SELECTED FOR 16-18 DEGREE F TEMPERATURE DIFFERENTIAL					
CHILLED WATER PIPE SIZE NOMINAL DIAMETER (INCHES)	RECOMMENDED FLOW RANGE		DELTA TEMP. (DEG F)	LOW TON RANGE (TONS)	HIGH TON RANGE (TONS)
	LOW (1)	HIGH (2)			
4	130	270	16	87	180
6	500	800	16	333	533
8	800	1500	16	533	1000
10	1500	2100	16	1000	1400
12	2100	3200	16	1400	2133
14	3200	4300	16	2133	2867
16	4300	5900	16	2867	3933
18	5900	7000	16	3933	4667

(1) LOW LIMIT BASED ON 0.8 FT PRESSURE DROP/100 FT
(2) HIGH LIMIT BASED THE MORE STRINGENT OF 4 FT PRESSURE DROP/100 FT, OR 10 FPS

a) Base Option – Select Cooling, Local Evaporative Cooling

Through this option local evaporative cooling should be considered if the UW opts not to provide chilled water cooling to the additional building growth. Evaporative cooling would be based on building occupancy and loads as well as available chilled water utility.

Evaporative cooling is a viable option in this climate due to the consistent low wet bulb temperatures throughout the spring, summer and winter season. On average the wet bulb temperature does not exceed 58-60°F and is below or equal to 55°F for over 8400 hours of the year. A lower temperature differential for cooling is also recognized which in affect increases the air quantities required to supplement the heat gains.

Direct evaporative cooling poses the most difficult control to satisfy space temperatures as well as eliminate biological factors from moist air streams entering and saturating ductwork. If controlled and maintained properly the benefits of evaporative cooling is an efficient and cost effective solution to building cooling.

Evaporative cooling is typically higher in yearly maintenance cost. Initial capital cost is dependent on the size and type of system installed and is typically higher than a chilled water cooling source due to increased system sizes caused by the low delta temperature differential and increased air quantities. The cost should be evaluated on a case by case basis.

The campus currently utilizes direct evaporative cooling at multiple buildings. Currently the UW implements a control scheme in existing buildings that has been successful for operations of the unit and building.

b) Option 1 – Upgrades to Satisfy Deficiencies and Projected Loads by Additions at the CEP

Phase 1: Add a 1200 ton chiller at year 2010 at the CEP to increase firm capacity to 2000 tons by 2011. This addition would include an increase in plant area of approximately 500 sqft, a new condenser water pump, a new cooling tower, and system piping and auxiliaries. An estimate for this addition is approximately $2,600,000.

Phase 2: Add an 800 ton chiller at year 2014 at the CEP to increase firm capacity to 2800 tons by 2015. This addition would include an increase in plant area of approximately 3000 sqft that could accommodate 1600 tons of cooling capacity. Estimates for this addition is approximately $3,640,000 for the large amount of infrastructure changes required.

Phase 3: Upgrade existing pumping, piping and auxiliaries at year 2020 to accommodate future growth beyond 2500 tons capacity. Replace approximately 1200 ft of 14” chilled water pipe with 18” pipe up to Centennial Complex takeoff to accommodate full projected load growth. Estimates for this addition is approximately $1,378,000 due to the large amount of infrastructure changes required.

Phase 4: Add an 800 ton chiller at year 2029 at the CEP to increase firm capacity to 3600 tons by 2030. An Estimate for this addition is approximately $2,080,000 since infrastructure is in place.

The resulting total estimated cost thru year 2030 is $9,698,000 which includes a 25% contingency and 10% engineering and design fee. All utility infrastructure piping will require evaluation after year 2030 due to the unknown conditions of loading on campus.

c) Option 2 – Upgrades to Satisfy Deficiencies and Projected Loads by Additions at the CEP and West Side of Campus

Phase 1: Add a 1200 ton chiller at year 2010 at the CEP to increase firm capacity to 2000 tons by 2011. This addition would include an increase in plant area of approximately 500 sqft, a new condenser water pump, a new cooling tower, and system piping and auxiliaries. An estimate for this addition is approximately $2,600,000.

Phase 2: Add two new 800 ton chillers at year 2014 at a new plant location on the West end of campus in Area A to increase firm capacity to 2800 tons by 2015. Firm Capacity would be thru full redundancy at both plant locations to maintain existing pumping strategies at the CEP. Existing system and utility infrastructure upgrades will not be required through all phases of the projected load growth. The plant would be approximately 3500 sq ft to include all equipment and infrastructure required for capacity to 2400 tons through three 800 ton chillers. An estimate for this addition is approximately $5,850,000 due to the new infrastructure changes required.

Phase 3: Add an 800 ton chiller at year 2029 at the West Campus CEP to increase firm capacity to 3600 tons by 2030. Estimates for this addition are approximately $2,080,000 since all infrastructure is in place.

The resulting total estimated cost thru year 2030 is $10,530,000 which includes a 25% contingency and 10% engineering and design fee. Through this scenario, all existing systems and utility infrastructure appear to be adequate to support the increase in capacity including the potential conversions after year 2030.

2. Options Summary

Evaporative cooling should be considered for all buildings and will be dependent on the type of building served, chilled water availability, and economics based on payback of each system in comparison to providing chilled water to the buildings. Chilled water along with evaporative cooling should also be considered for demand reductions to the existing system capacity.

It is recommended to increase the existing firm capacity on campus in Phase 1 of both options noted above. The UW should account for approximately $2,250,000 in design and construction fees for this addition.

For phase II through III the chilled water capacity should be evaluated on a year by year basis due to any shift in projected loads from the evaporative cooling additions or load projection reductions. If capacity reaches that shown in Figure III-C-1 it is recommended to add a west campus chiller plant noted in Option #2 above for the following advantages.

- The system provides full redundancy and firm capacity thru 2030.
- Lengthy shutdowns are not required for infrastructure upgrades.
- Infrastructure upgrades are not required.
- Addition of a west campus plant maintains the remaining useful life of the equipment installed at the CEP in 2008-2009.

- Pumping head and energy use is not increased at the CEP

The majority of these advantages are present since capacity is provided at both ends of campus shifting them into halves versus accomplishing the entire load at one end of campus. The existing 800 ton chiller will need to be evaluated on a yearly basis to determine if replacement is required since the equipment may have 10-20 years of useful life as indicated within Section II, Existing Conditions. The UW should account for approximately $8,800,000 in design and construction for Option 2 additions through year 2030.

E. Core Campus Utility GHG Emissions Reduction Analysis

1. General Overview

A second aspect to the options evaluation defined in Section IV, B thru D above includes review of Green House Gas (GHG) Emissions for core campus utilities. The evaluation includes an estimated campus projected outlook of GHG emission production for current operation and estimated potential reductions of GHG's that each option can produce for the core campus utility.

Preliminary economic analysis of the options relating to carbon trade tax offsets defined above were evaluated with the reductions and can assist in providing suggestions to effectively meet the American College and UW Presidents Climate Commitment (ACUPCC), signed and recently committed to by the UW. The commitment made by the UW is 15% GHG emissions reduction compared to year 2005 by year 2015 and 25% emissions reduction compared to year 2005 by year 2020.

2. Projection and Annual Load Growth

The first step in defining appropriate options for emissions reduction was to establish a baseline of current core campus CO2E production and outlook for campus. This is otherwise noted as Business As Usual and represents what the GHG production and growth would look like if the campus continues its current practice for generation of heat and provisions for electrical utility for the growth that is anticipated on the campus. Business as Usual yearly values for the UW Core Campus Utilities is defined in Table IV-E-2-2 shown below for reference and within Appendix IV-E. Values of GHG production is summarized in for the current year 2009 thru year 2030 based on values defined from historic load and energy consumption data.

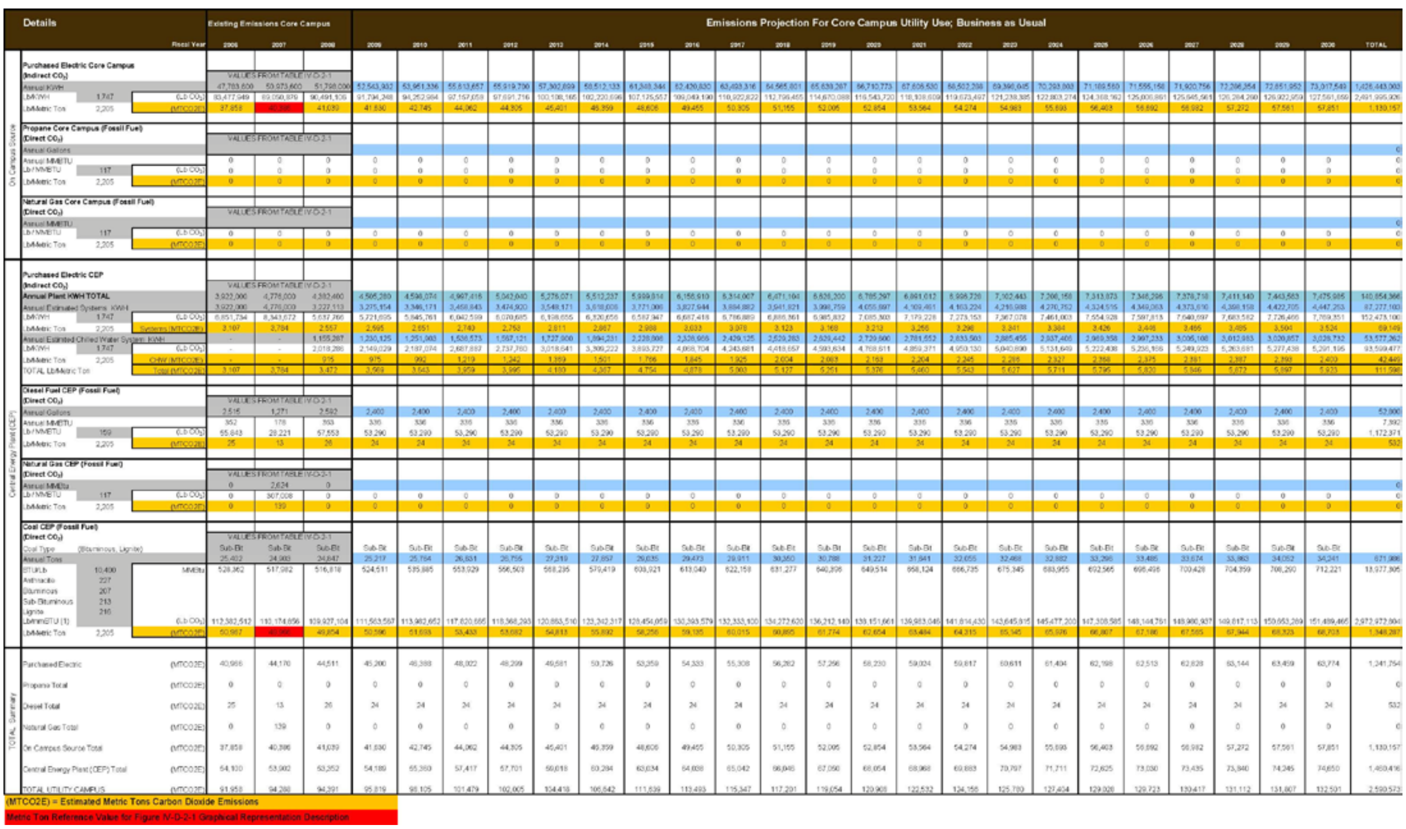
The Historic load and energy consumption data was gathered from the UW and previous studies performed which summarized the core campus thermal and electrical usage over the past three or more years. This data is presented in Table IV-E-2-1 below. This data enabled a starting point and a trend to be established for various energy sources added to by future load growth defined by the UW and LRDP in Section III.

Table IV-E-2-1

Core Campus Historic Fuel / Utility Use											
Year	Coal (Tons)	Coal (Tons)	Natural Gas (MMBTU)	Natural Gas Campus (MMBTU)	Natural Gas CEP (MMBTU)	Propone (Gal)	Propone (Gal)	CEP Deisel Fuel	Purchased Electric KWH	Purchased Electric Campus KWH	Purchased Electric CEP KWH
1992									53,445,897 (1)		
1993									53,941,369 (1)		
1995									52,184,047 (1)		
1995	20233 (1)								56,167,979 (1)		
1996	19443 (1)								46,972,247 (1)		
1997	22717 (1)		58,807 (1)						60,338,399 (1)		
1998	22995 (1)		104,822 (1)						58,092,656 (1)		
1999	22892 (1)		98,058 (1)						58,793,723 (1)		
2000	21963 (1)		96,486 (1)						58,604,939 (1)		
2001	22787 (1)		103,020 (1)						60,436,600 (1)		
2002	21864 (1)		102,155 (1)						56,858,767 (1)		
2003	23958 (1)		104,706 (1)						60,759,668 (1)		
2004	24097 (1)		115,315 (1)						60,748,033 (1)		
2005	24059 (1)		108,453 (1)						60,840,819 (1)		
2006	16040 (1)	25402 (2)	113,063 (1)	113021 (2)(3)	0 (2)		1055 (2)	2515 (2)	59,372,098 (1)	51,705,600 (2)	3,922,000 (2)
2007	13783 (1)	24903 (2)	107,146 (1)	105568 (2)(3)	2624 (2)	6,841 (1)	7582 (2)	1271 (2)	63,602,733 (1)	55,749,600 (2)	4,776,000 (2)
2008		24847 (2)		87556 (2)(3)	0 (2)		8547 (2)	2592 (2)		56,180,400 (2)	4,382,400 (2)
2009											

(1) Cited From Green House Gas Inventory For The University of Wyoming 1990-2007, Linse n. Anderson and Alyssa Wechsler, 2008.
(2) Historical Data Provided by Physical Plant Management Staff for the Past 3 years per Base Monthly Spreadsheet Data
(3) Student Housing Off Core Campus

Table IV-E-2-2 (Also Provided in Appendix IV-E)



Each core utility produces a quantity of CO2 per kwh or 10^6 Btu based on the energy or fuel utilized. These quantities are defined in Table IV-E-2-2 which is then quantified in terms of Metric tons of CO2 (MTCO2E) per utility overall consumption, indicated as orange highlighted in the above table. The primary utilities on campus consist of fossil fuel and purchased electric and the projected usage rate is identified within the blue rows above.

Fossil fuel consists of a mixture of natural gas, propane, fuel oil, and coal. The dominate fossil fuel is coal which produces steam at the Central Energy Plant for use on campus. The secondary fuels produce local heat or are used for process systems such as the emergency generator at the central energy plant. Each of these secondary fossil fuels is insignificant to coal as can be seen in Table IV-E-2-1 and IV-E-2-2 above and within the appendix and Figure IV-E-2-1 shown below.

The type of coal utilized affects the net quantity of GHG emitted from the burning of fossil fuel. Sub-Bituminous coal is currently being burned to produce heat at the plant. If the type of coal is revised in the future the projected outlook will need to be revised as this is one of the primary producers for the campus.

The other dominant source of CO2 for the campus is in the form of an indirect source produced by secondary company. For this specific case the electricity purchased by the campus is the indirect source. Purchased electric like all other emitting utilities can be quantified in terms of CO2/KWH defined by the local utility company or through the EPA.

For this evaluation Rocky Mountain Power (RMP) has indicated that the 2006 quantity of CO2 produced per KWH of power supplied is 1.747 LBCO2E/KWH per parent company PacifiCorp's certified data. Current values thru year 2008 are being evaluated by PacifiCorp to certify the CO2 content of the electricity produced.

To note: Numbers have been evaluated by Pacificorp company and RMP has indicated the source to be approximately 1.77 LBCO2E/KWH for year 2007. Although greater, the value of 1.747 recently identified is utilized for this evaluation due to the recent update and minimal increase noted. The quantity of CO2 produced by the electric utility is significantly higher than other utilities throughout the country. It is believed that this is due to electricity being produced from the large and cost effective source of coal that is found in Wyoming.

To summarize the numbers visually, a graphical representation of Business As Usual Emissions is represented in Figure IV-E-2-1 below. The graph was split to identify initial quantity and where the emissions originate from in terms of fossil fuel and purchased electricity for the campus. The values on this graph at year 2007 shown in red arrows correlate to the MTCO2E indicated in red on Table IV-E-2-2 This also provides an initial sense of where there is opportunity to reduce GHG's and for each core utility based on the options defined above.

From the load growth pattern thru year 2030 a representative percent of each core campus utility can be derived and is indicated in Figure IV-E-2-2 for the current campus GHG production thru year 2030. Percentage from yearly to total will be similar as campus operations are not being revised to reduce GHG emissions.

Figure IV-E-2-1

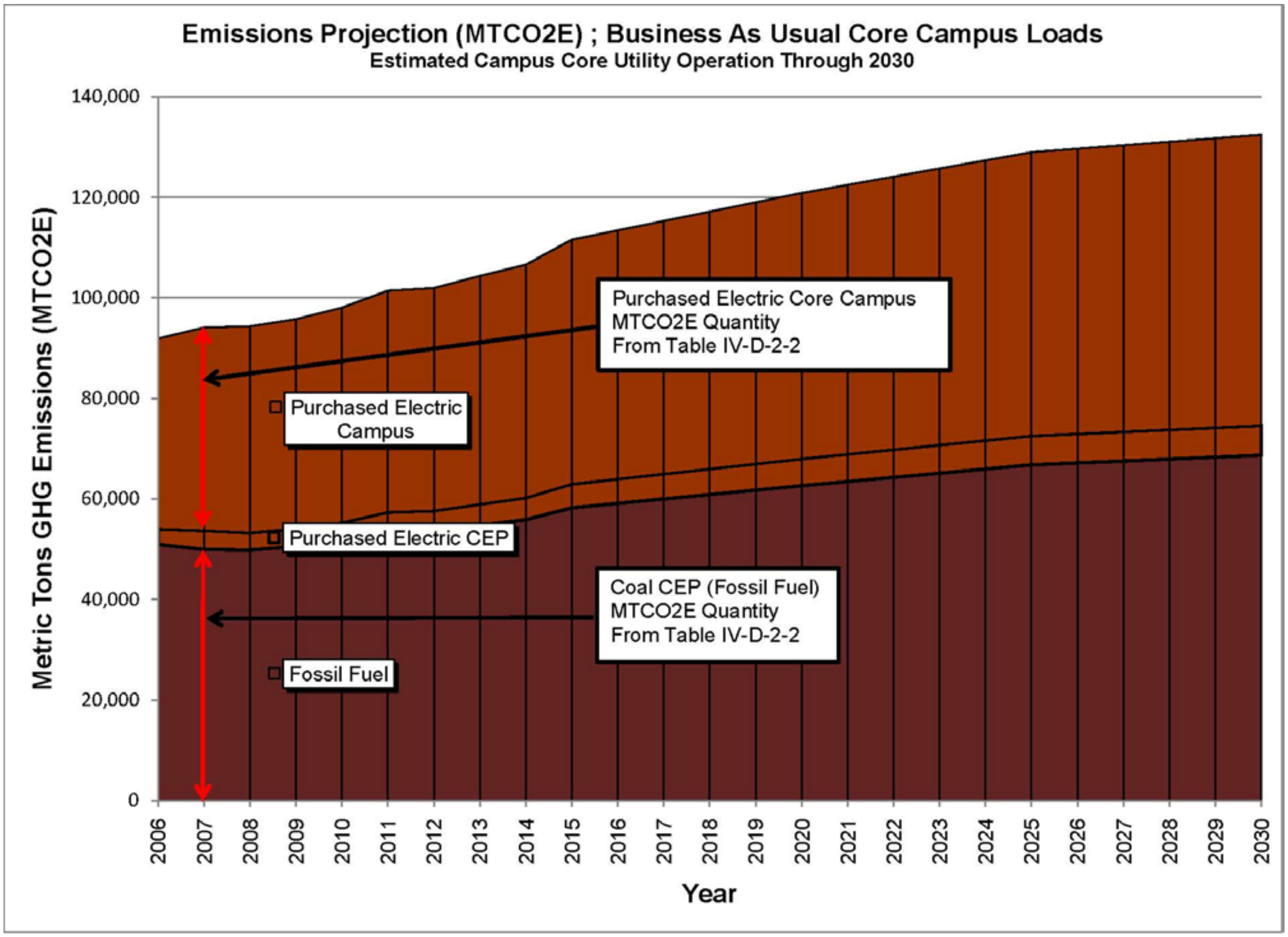
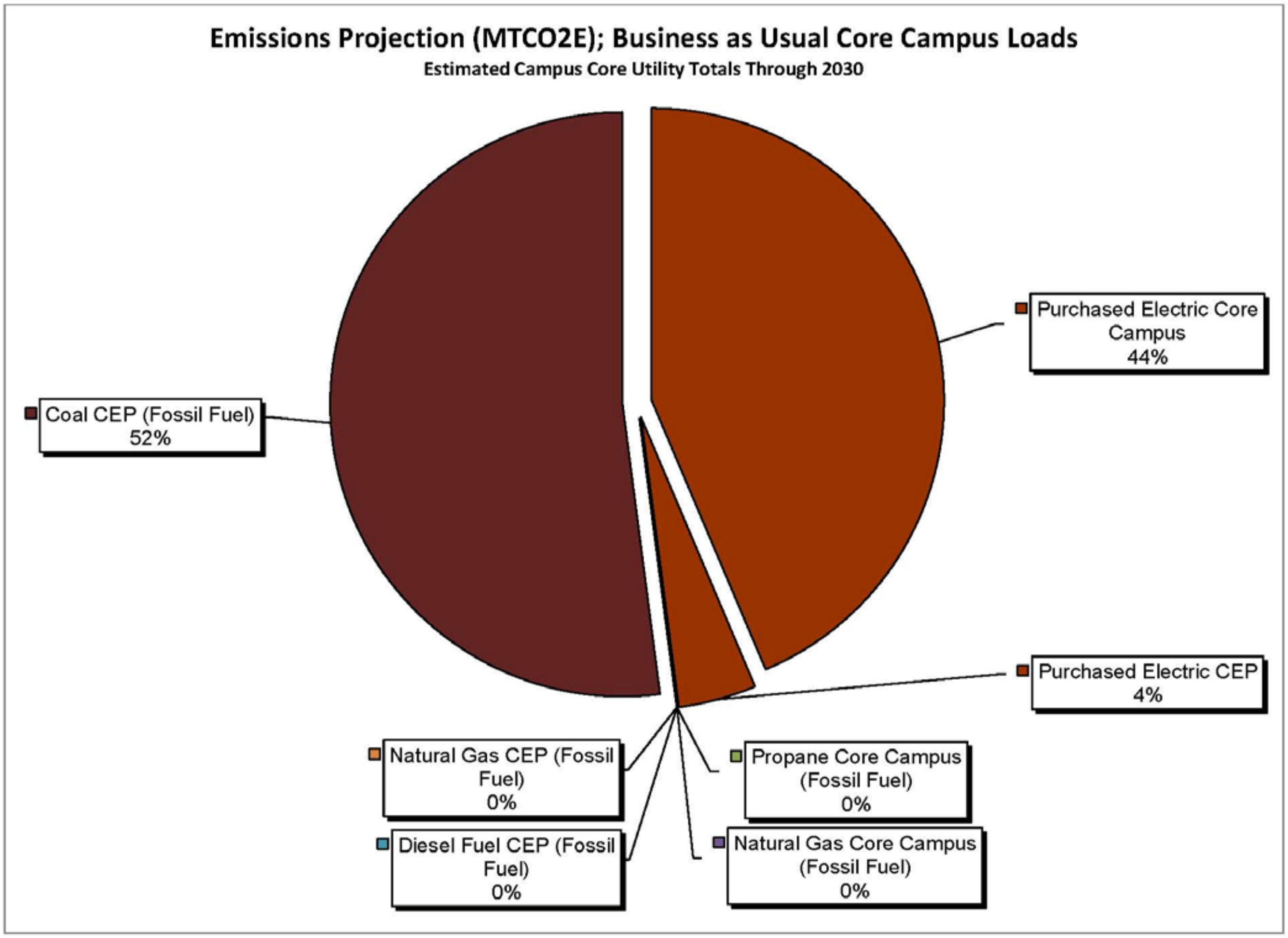


Figure IV-E-2-2



3. Options Evaluation

Applying the options noted above to the campus master plan present opportunities for GHG emission reductions to both fossil fuel and purchased electric defined in the Business as Usual emission projection.

The estimated potential of each option through year 2030 is defined in Table IV-E-3-1 and IV-E-3-2 within Appendix IV-E and is in terms of net reduction or addition MTCO2E to the projected carbon use on campus. By identifying these quantities each option capability can be paired as appropriate to address the UW's goals for emissions reductions on campus.

The scenarios in which these options are placed are unlimited with respect to timeframe and paralleling specific options. Each option however is also limited with respect to the quantity of emission each can reduce simply due to the characteristics of the fuel used as well as the physical size of the equipment utilized. Multiple options may be necessary to achieve the quantity of emissions reduction required by the UW.

Scenarios have been defined as values in Table IV-E-3-3 and IV-E-3-4 located in the Appendix and graphically represented in Figure IV-E-3-1 thru IV-E-3-21.

Each scenario is evaluated in terms of projected emissions reductions and resultant core campus utility GHG production. Values and economics are applied to the scenarios and are based on estimated fuel cost, equipment and maintenance cost and anticipated timeframes of implement. These values are preliminary and should be evaluated in detail due to any revised campus projections or options that are implemented in the 20 year outlook that the UW is willing to undertake to accomplish emissions reduction goals noted.

- Reduction Option 0 - Base No Change to Operations

Figures IV-E-3-1 thru IV-E-3-2 below indicates the estimated quantity and ratio of purchased electricity to fossil fuel previously defined. These quantities will be utilized to compare emissions reductions from the scenarios of each option.

Figure IV-E-3-1

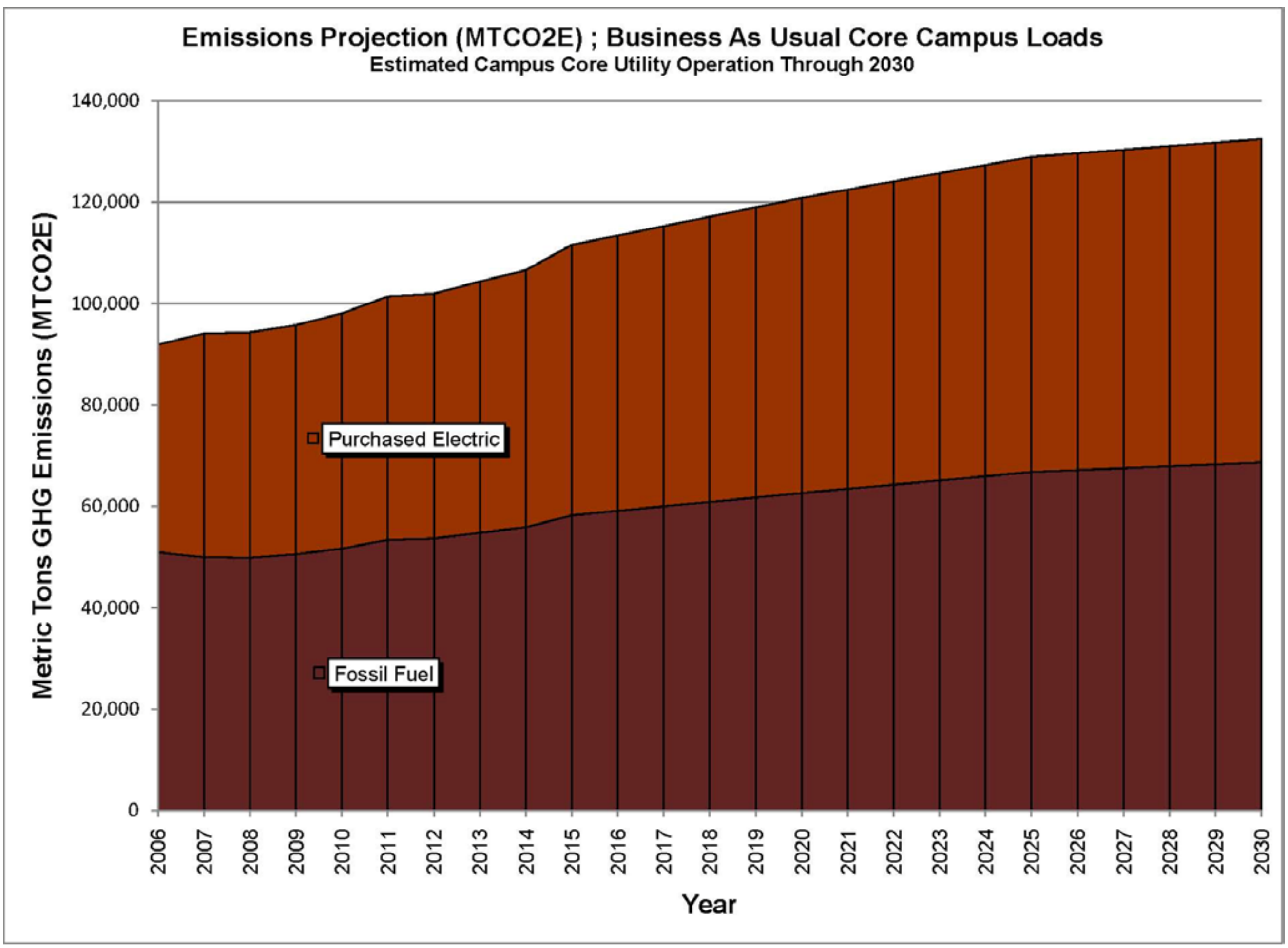
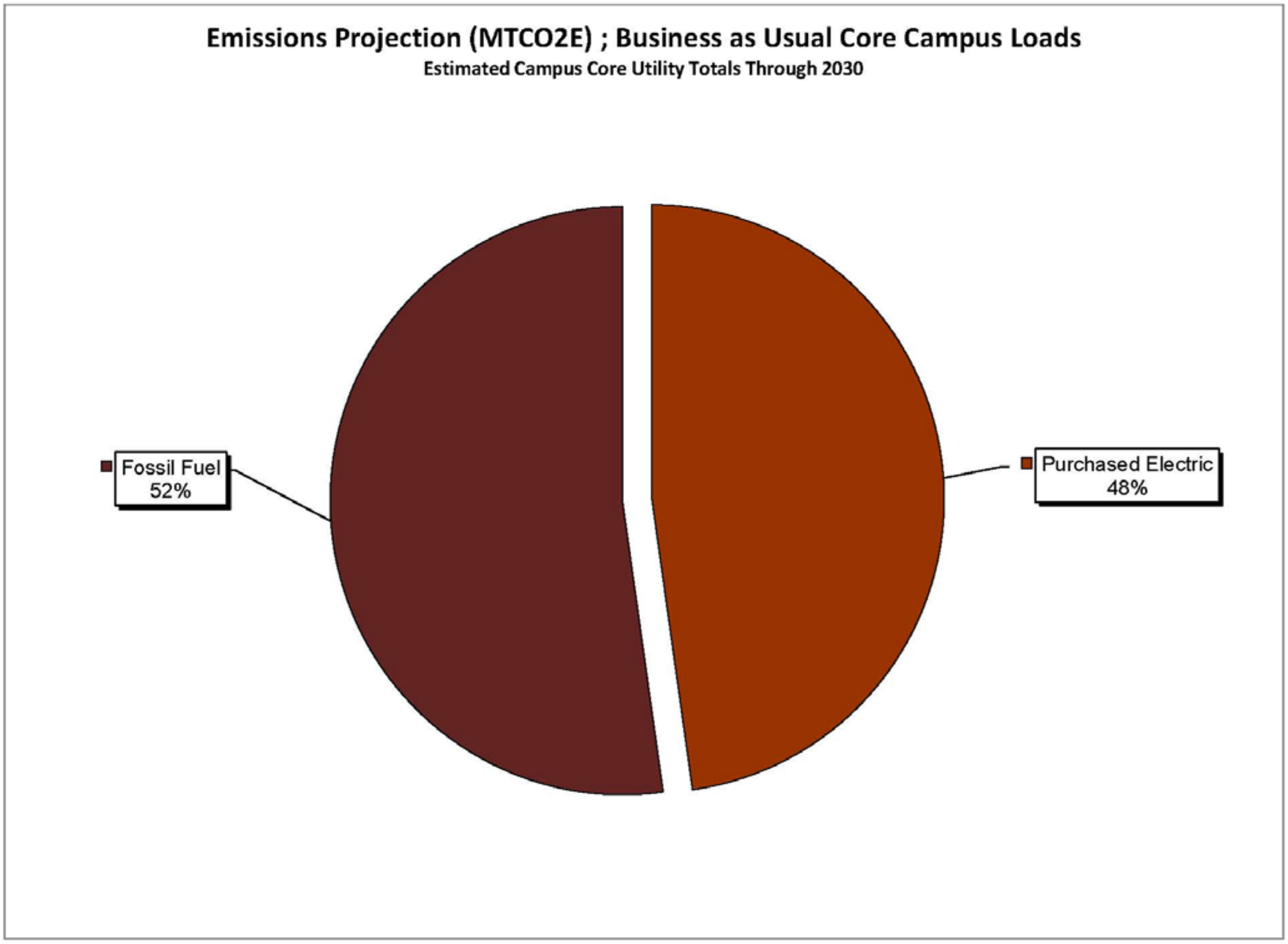


Figure IV-E-3-2



- **Reduction Option 1 - Purchased Electric Utility Reduction Plan Estimate (30%)**

  A significant quantity of CO2 indirectly produced by the campus is from electricity that is purchased from Rocky Mountain Power and Utilized on Campus. This quantity of CO2 is solely dependent on how the utility produces power and how this power is distributed to their users. In recent years there has been a demand by the public as well as government offices to take action and reduce the net quantity of GHG emissions produced.

  Because of this demand the utility providers have started to introduce plans and actions towards achieving a cleaner power source that is added to the overall grid. These plans generally consist of implementing newer technologies and plants that utilize renewable resources such as wind or renewable fuel sources. A predicted reduction level of 30% emissions by the year 2030 is applied in Figure IV-E-3-3. The reduction is added to each year that will eventually equal 30% total reduction in the year 2030 as compared to present day.

Figure IV-E-3-3

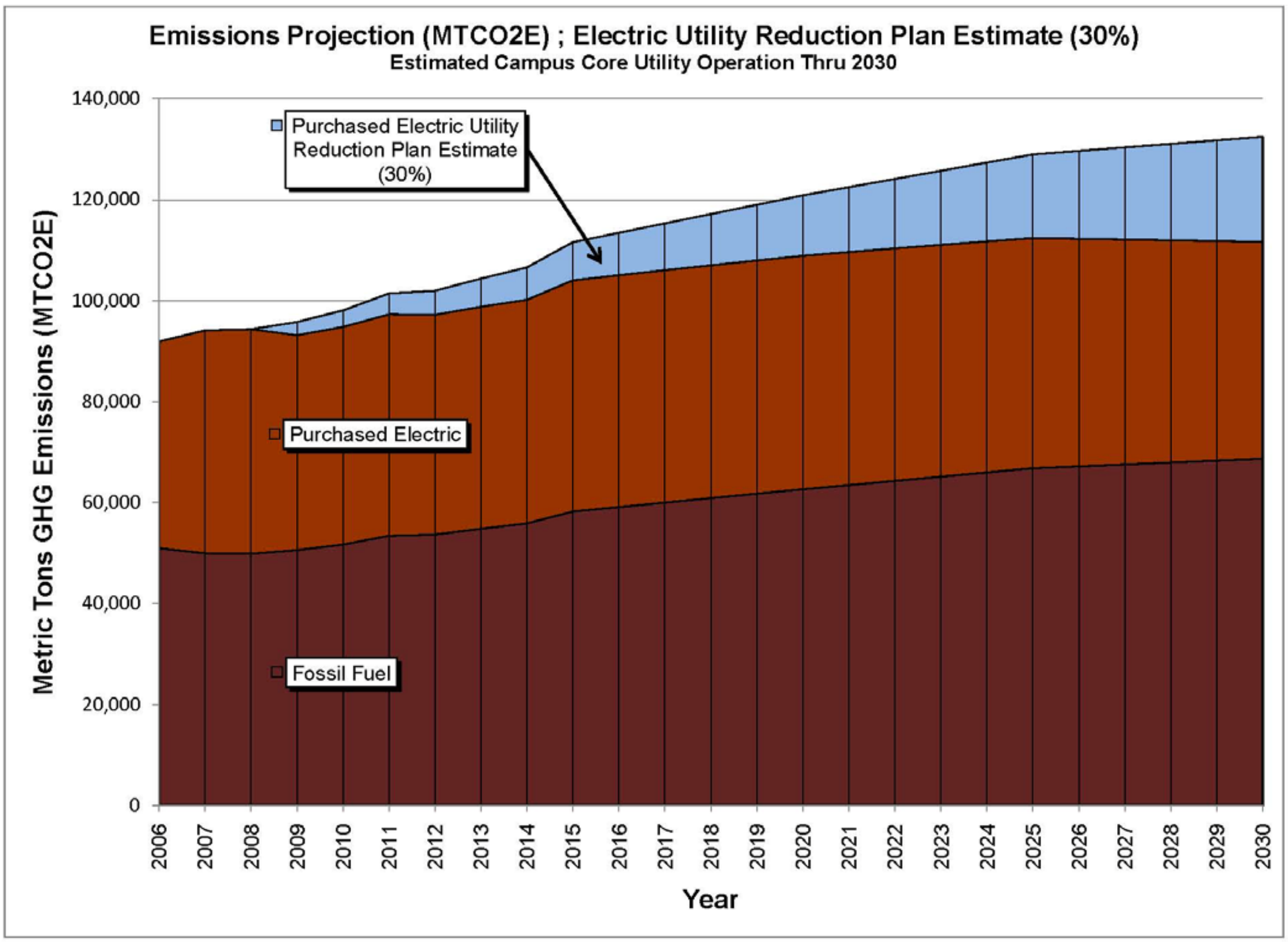
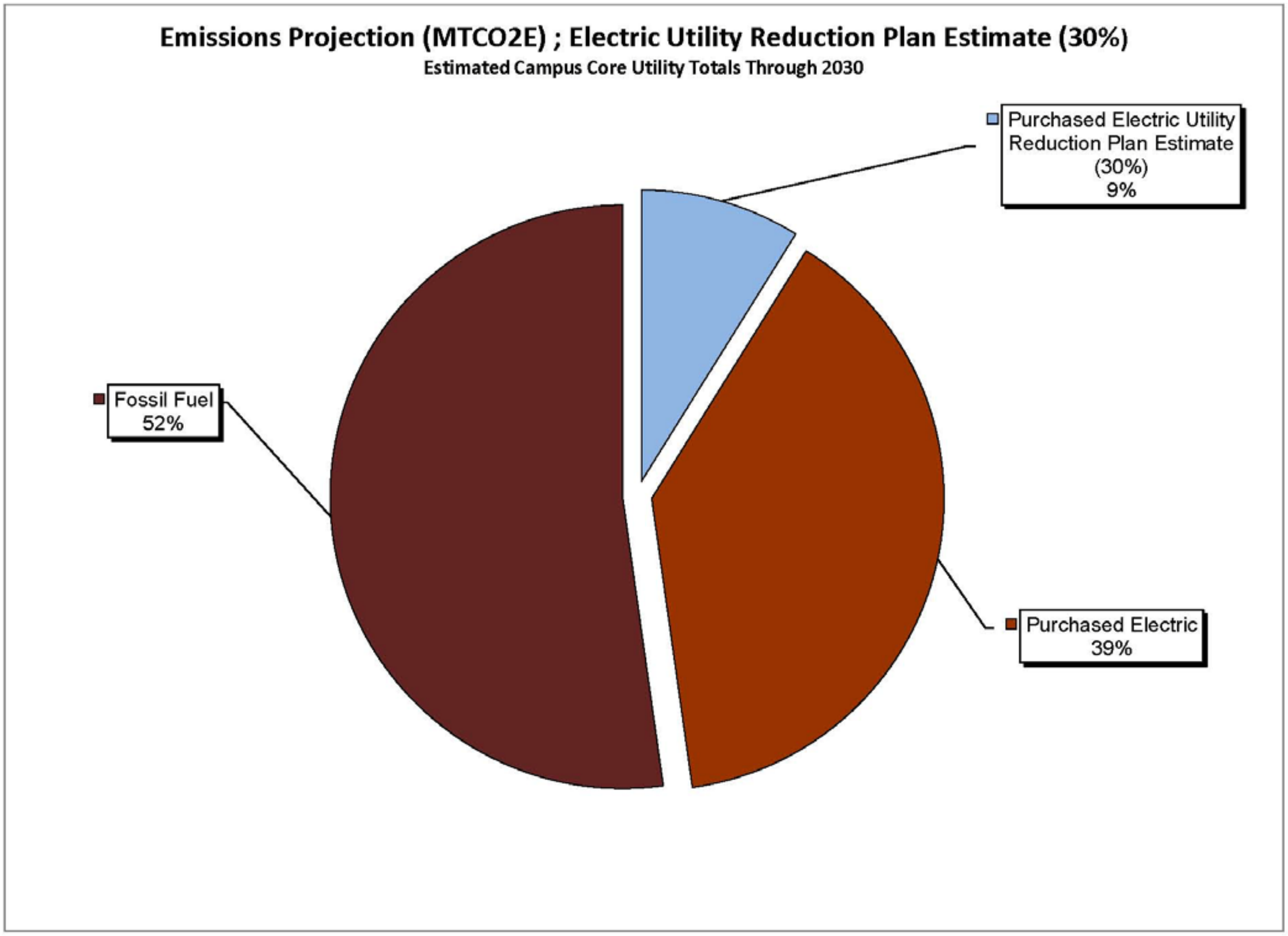


Figure IV-E-3-4



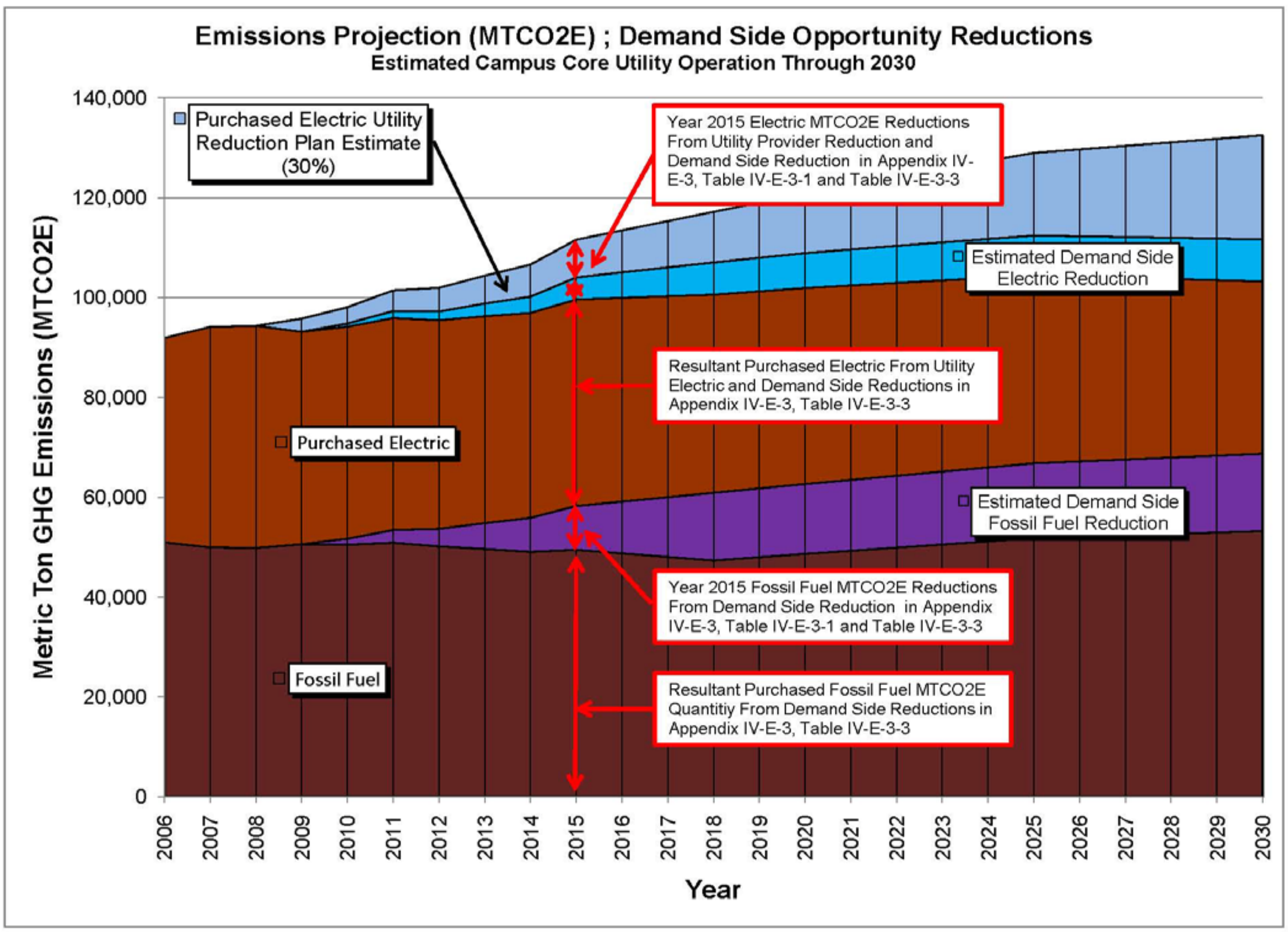
The percentage of CO2 reduction from any planned utility reduction is only applied to the purchased electric utility for the campus. Further discussion with the utility provider is required to confirm the reduction assumption above accurately represents the utility quantity from year to year.

- **Reduction Option 2 - Demand Side Reductions**

  To meet goals of campus GHG emissions, existing building renovation as well as new construction efforts will be required to increase building efficiencies with respect to heat, cooling, and electrical use. A series of recommendations have been identified that will contribute to the overall efficiency and decease the demand placed on the campus mechanical and electrical systems.

  Demand side reduction examples include solar thermal heat for domestic hot water, as well as control improvements, mechanical system improvements, lighting controls and scheduling for the various buildings on campus evaluated in Section IV-C-2 above. The demand opportunity reductions are represented in Figure IV-E-3-5 below The figure also includes a series of arrows and reference points that describes where each reduction values is coming from in relation to Table IV-E-3-1 thru IV-E-3-4 within Appendix IV-E. For this example the values indicated are for the red highlighted cells in Table IV-E-3-1 and Table IV-E-3-3 of which should be the same values. Note that these reductions in this figure are specific to purchased electric reductions and fossil fuel reductions.

Figure IV-E-3-5



To simplify the overall reduction of GHG's as compared to the business as usual volumes the figures are arranged in the following configuration in Figure IV-E-3-6. This figure represents what types of reductions are still required to achieve overall campus neutrality as well as specific component reductions that are still available.

Figure IV-E-3-6

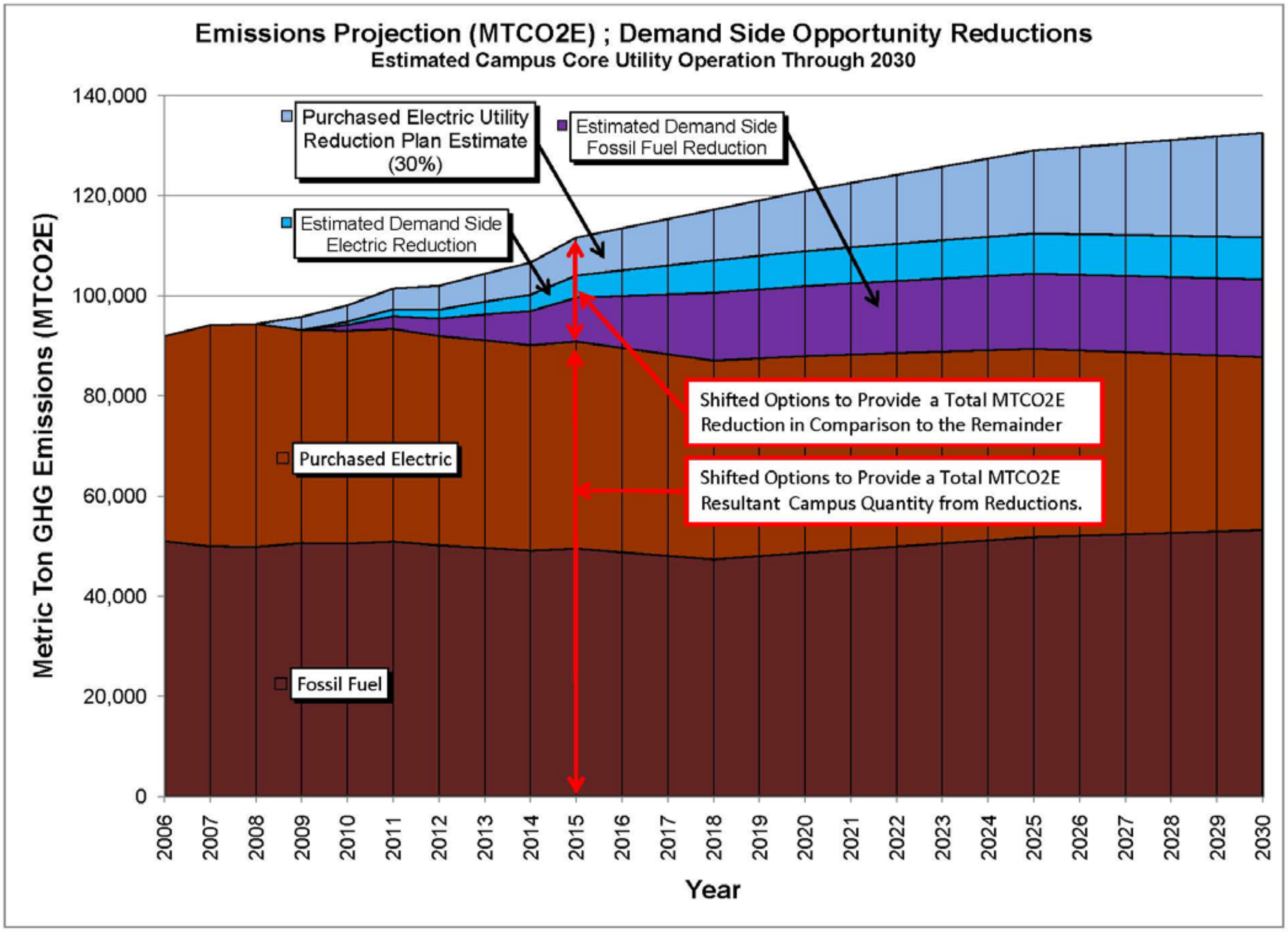
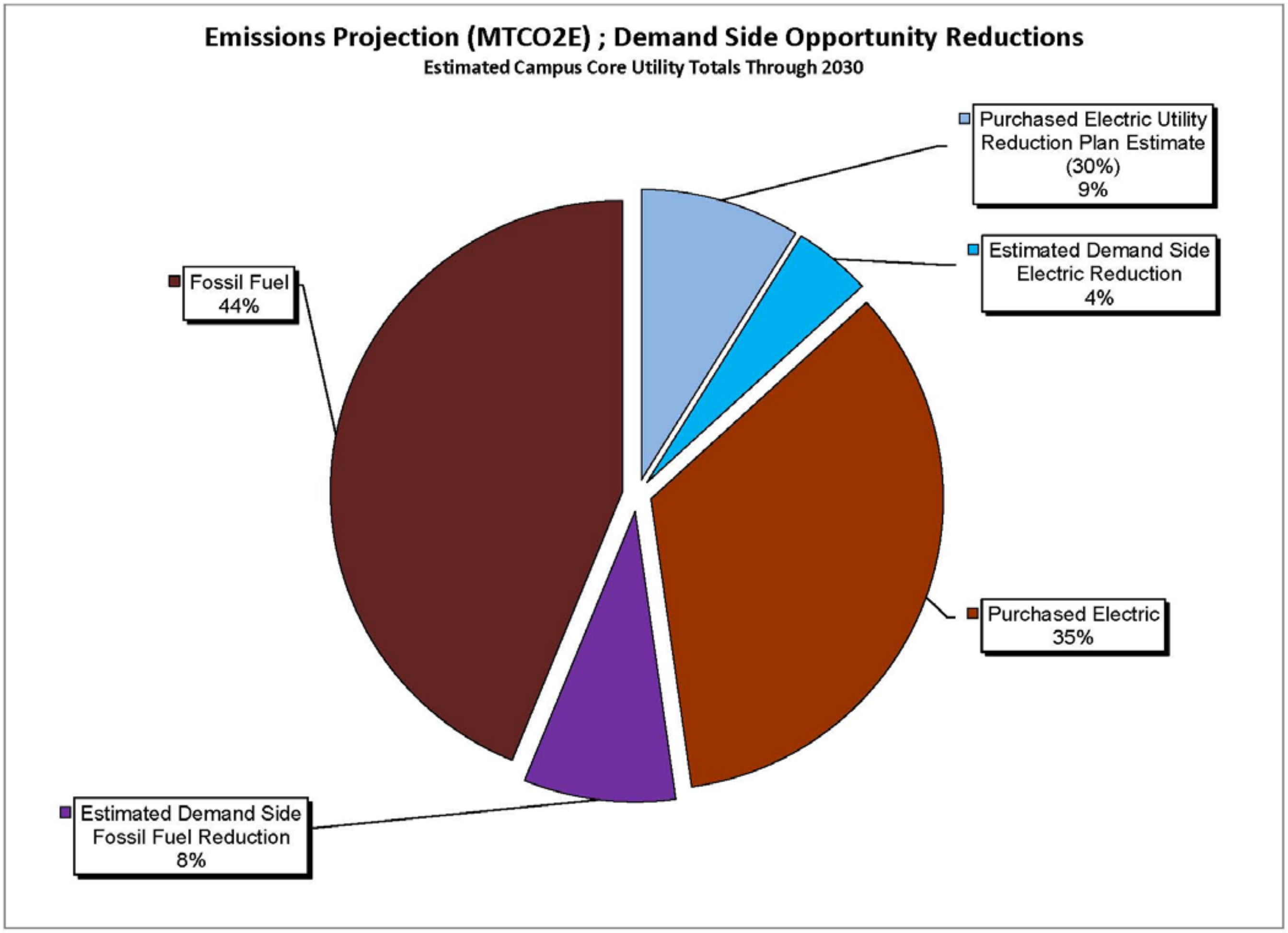


Figure IV-E-3-7



The demand side opportunity percentages defined above provide an initial sense of savings and will require further evaluation under separate modeling and study to accurately represent the potential for the existing campus buildings.

Demands side opportunity reductions are applied to each option within this section as is a primary recommendation for the campus master plan that will reduce campus GHG emissions.

- **Reduction Option 3 – Conversion to 100% Natural Gas from Coal**

  Fuel conversion to natural gas at the heating plant reduces GHG emissions simply due to the characteristics of the fuel being burned. Natural gas produces approximately half of the CO2 emissions that coal produces. The net reduction is applied to the fossil fuel utility and will require further evaluation based on economics since the first cost of natural gas is currently higher than coal currently burned at the plant. Natural gas estimated emissions reductions is shown in Figure IV-E-3-8 and percentages identified in Figure IV-E-3-9.

Figure IV-E-3-8

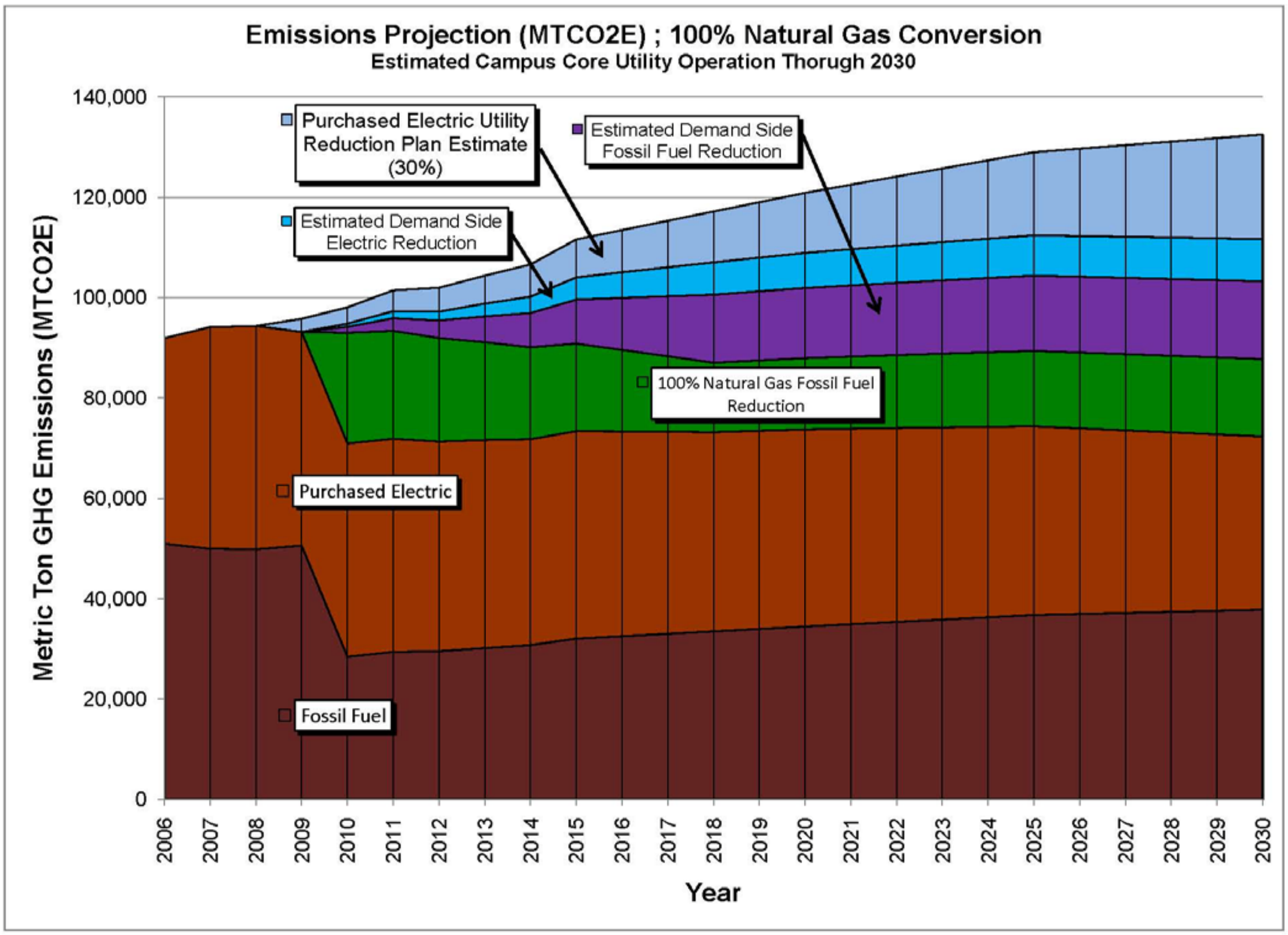
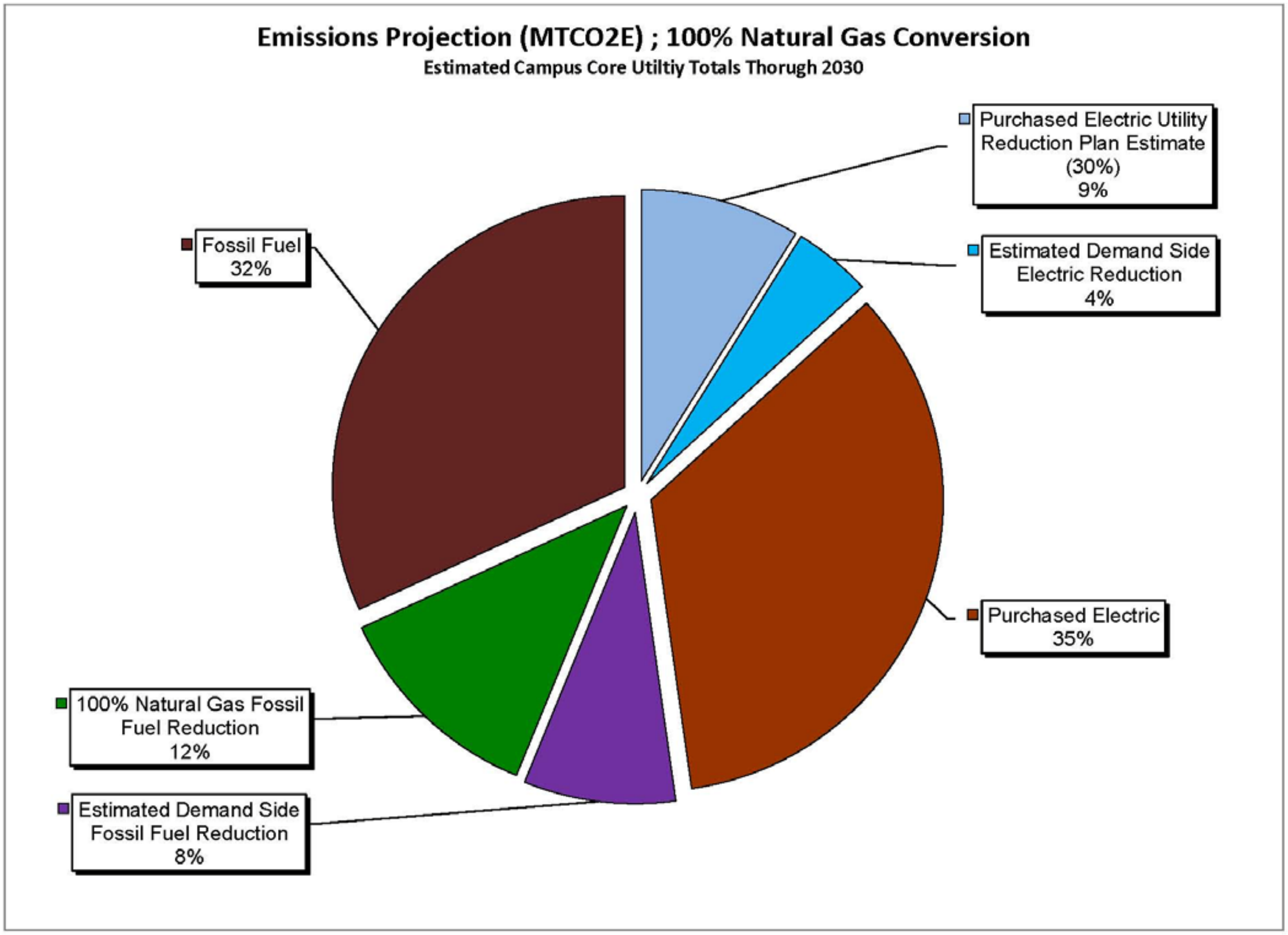


Figure IV-E-3-9



- **Reduction Option 4 –Coal/Biomass 10% by Weight Mix at the CEP**

  An option to burn woody biomass at the existing plant as defined above includes a net GHG production of zero per weight of biomass utilized. Additional coal is required to offset the lower heating value of coal however still presents a net reduction to the emissions outlook for the fossil fuel utility.

  The biomass option indicated in Figure IV-E-3-10 and Figure IV-E-3-11 represents a continuous percentage of biomass burned at the CEP through the year 2030.

Figure IV-E-3-10

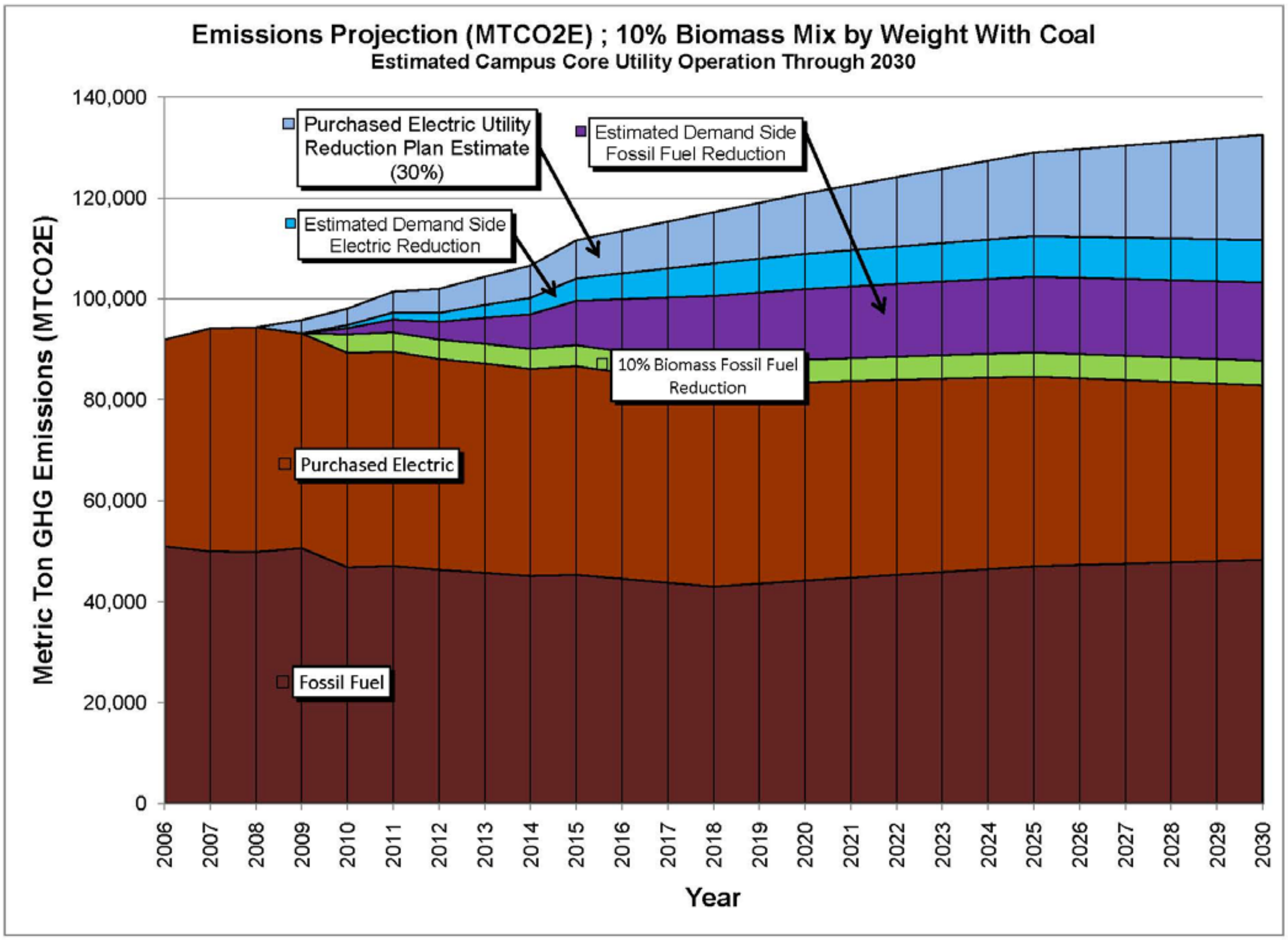
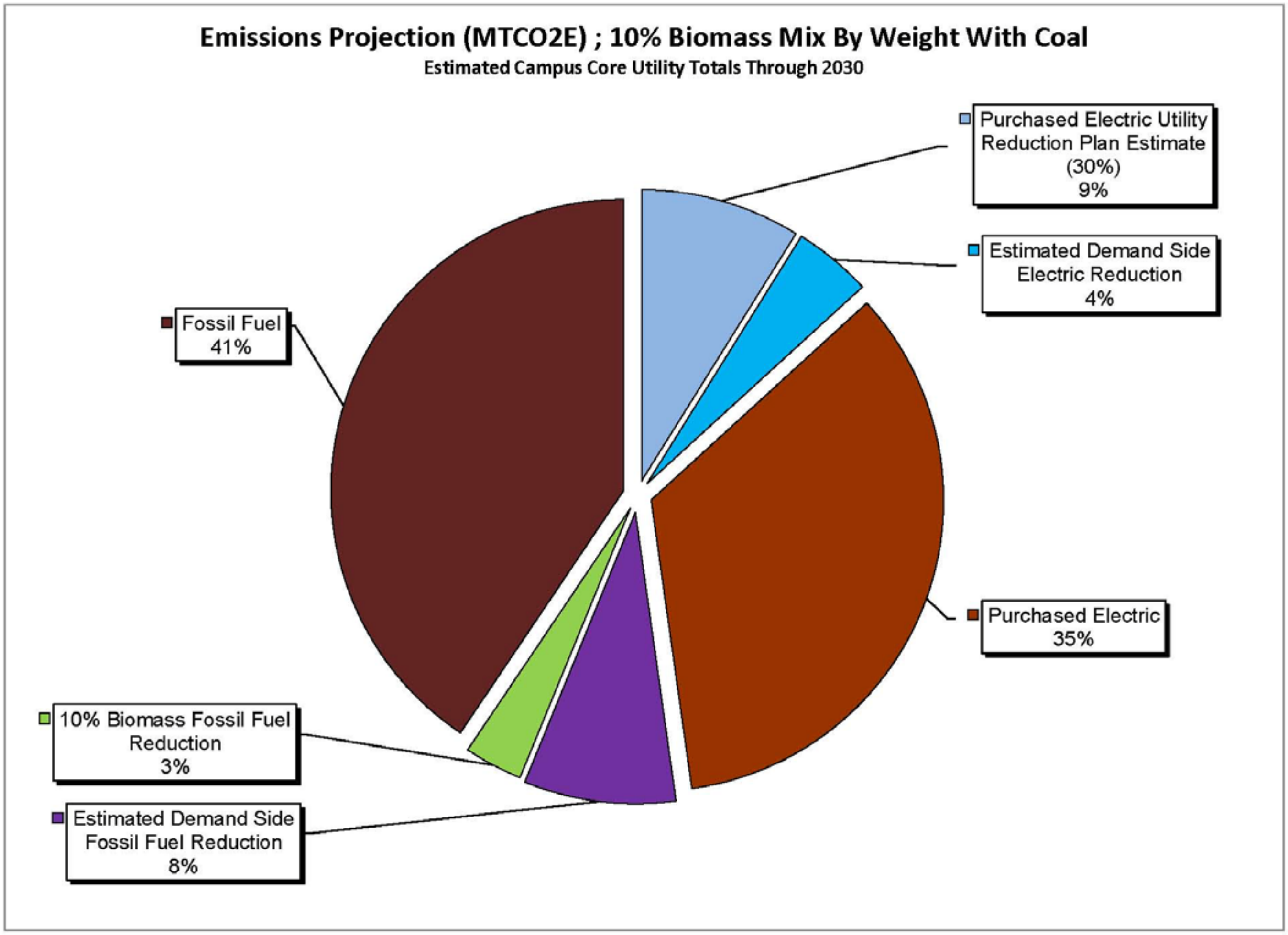


Figure IV-E-3-11



- **Reduction Option 5 – 10% Biomass Converting to 100% Biomass by Weight at the CEP**

  Burning biomass is a viable option at the plant and should be considered in a constant quantity that does not require additional boiler capacity up to the point where biomass is burned 100% by weight to meet emissions and still achieve capacity due to the lower heating values of dried wood. Similar recommendations are provided in Section IV-2 for burning 100% biomass.

  The biomass option indicated in Figure IV-E-3-12 and Figure IV-E-3-13 represents a percentage of biomass burned to 2020 which is then converted to 100% thru year 2030 to increase the net GHG reduction applied to the fossil fuel utility. By utilizing 100% biomass, all of the fossil fuel MTCO2E is eliminated from the Core Campus Utility which is approximately 52% of the campus core emissions.

Figure IV-E-3-12

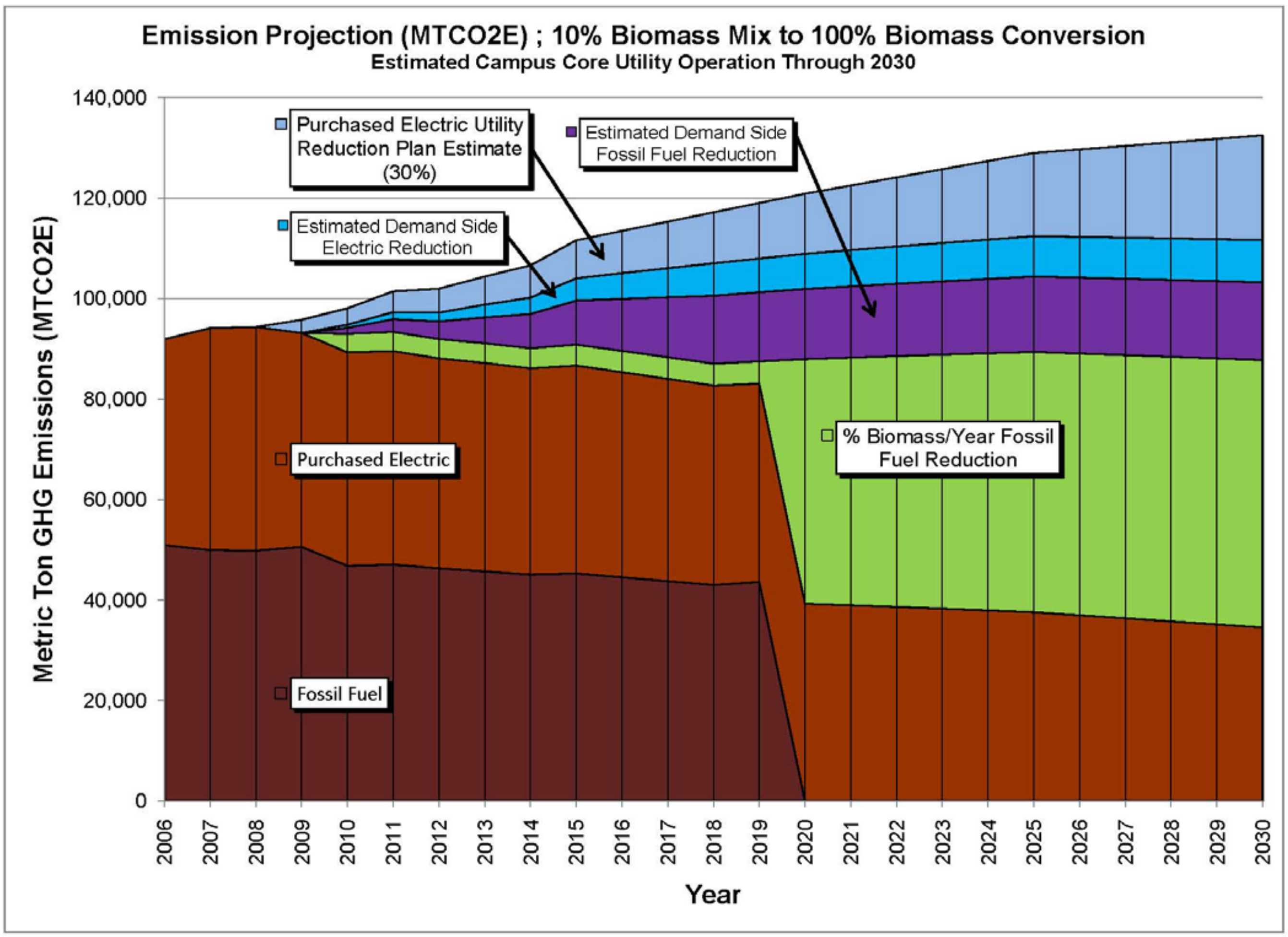
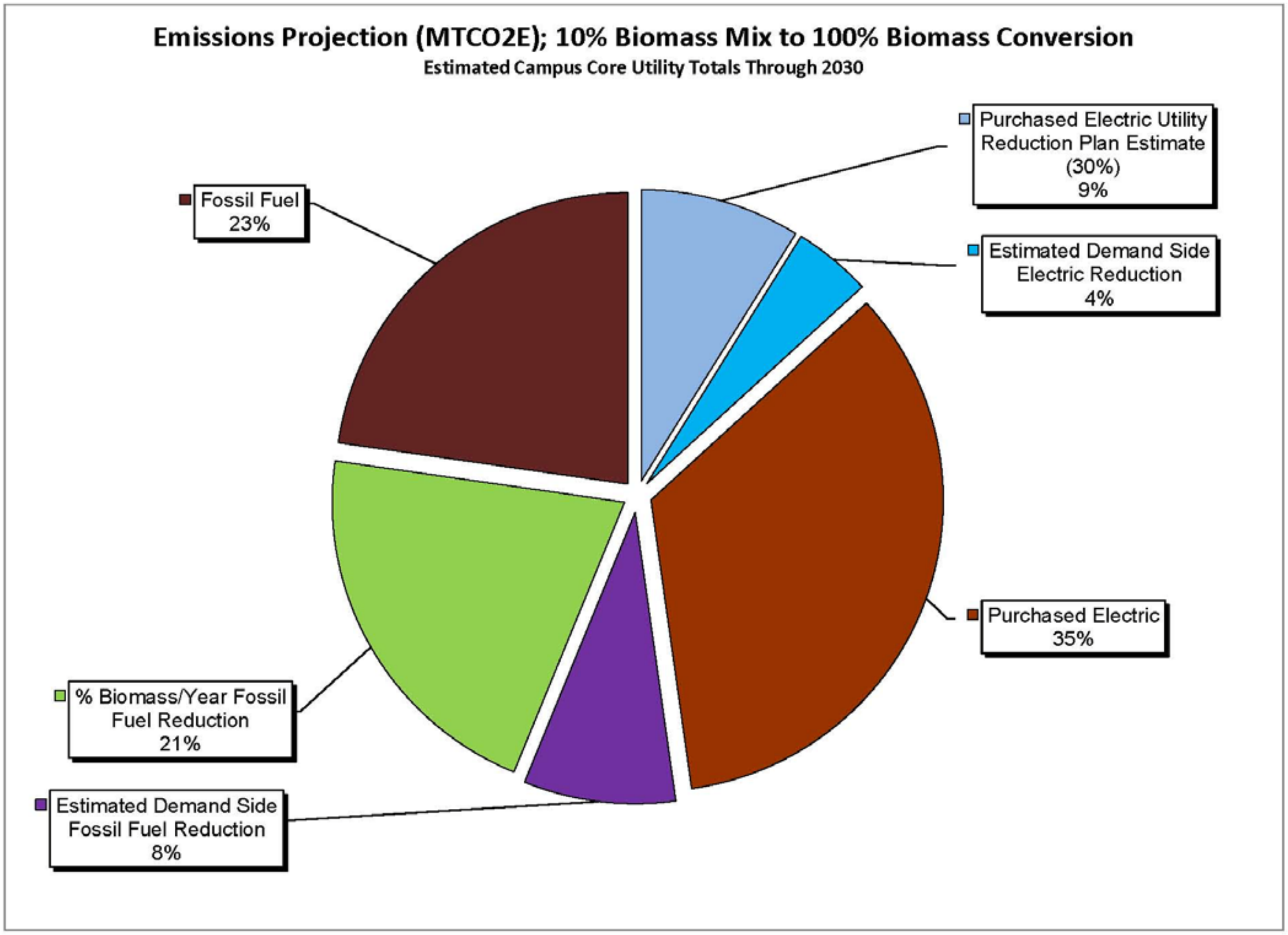


Figure IV-E-3-13



- **Reduction Option 6 – 3.5 MW Natural Gas Heat and Power (H&P)**

  Heat and power systems are a viable option to reduce emissions for the campus as two sources may be considered pending the type of system and fuel utilized to produce power. The advantage of any Heat and Power is that electrical production takes place and waste gas is utilized to produce heat on campus Disadvantages are associated with present value and payback of the system indicated in section IV-B above. But need to be evaluated within the carbon tax potentials identified later in this section.

  In the case defined in Figure IV-E-3-14 and Figure IV-E-3-15 the system evaluated is a combustion turbine with natural gas as the fuel. An increase in fossil fuel is recognized due to the increase in fuel required for power production and internal inefficiencies. A decrease in purchased electricity is noted from power production by removing electricity/CO2 from the grid.

Figure IV-E-3-14

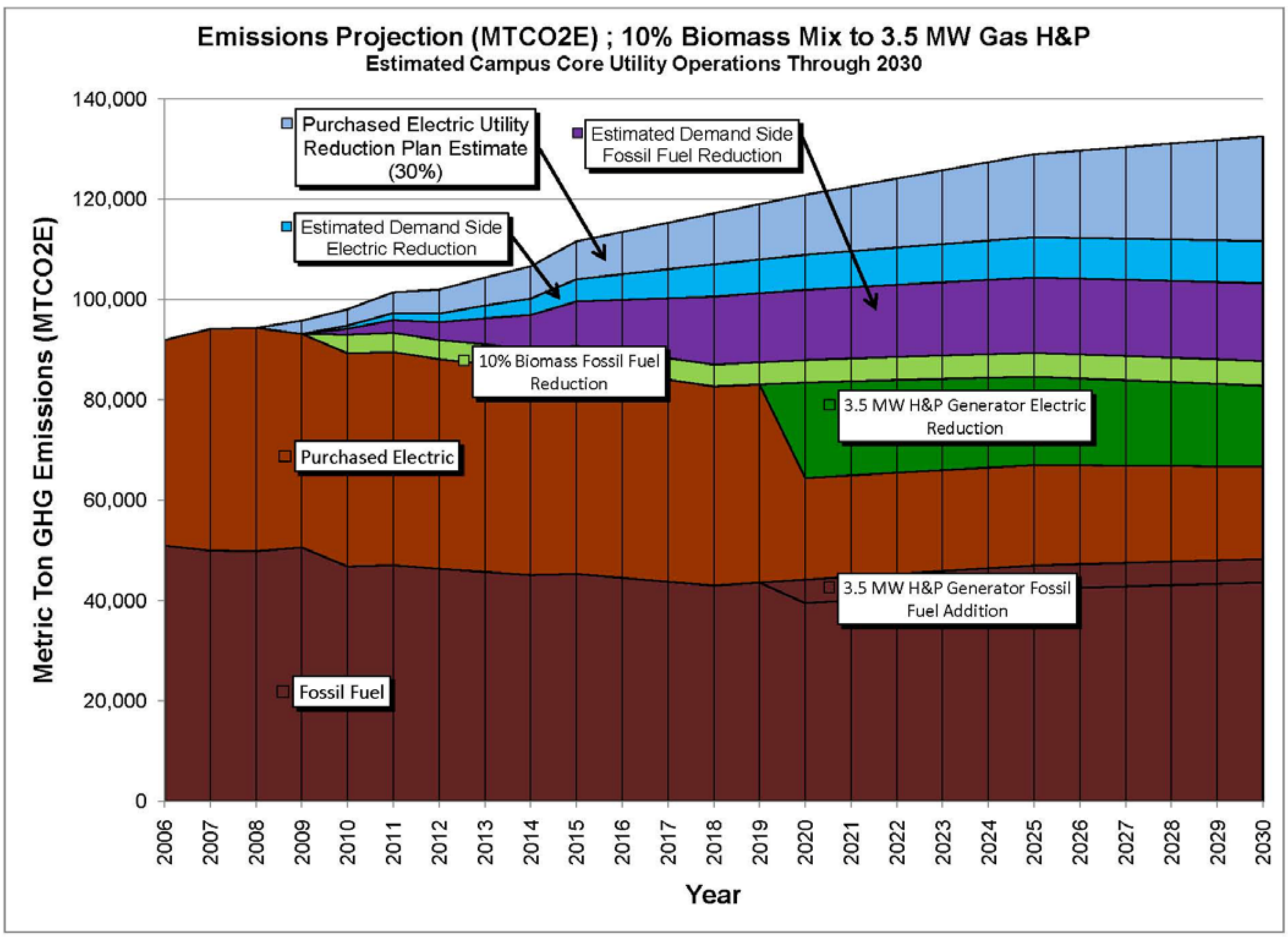
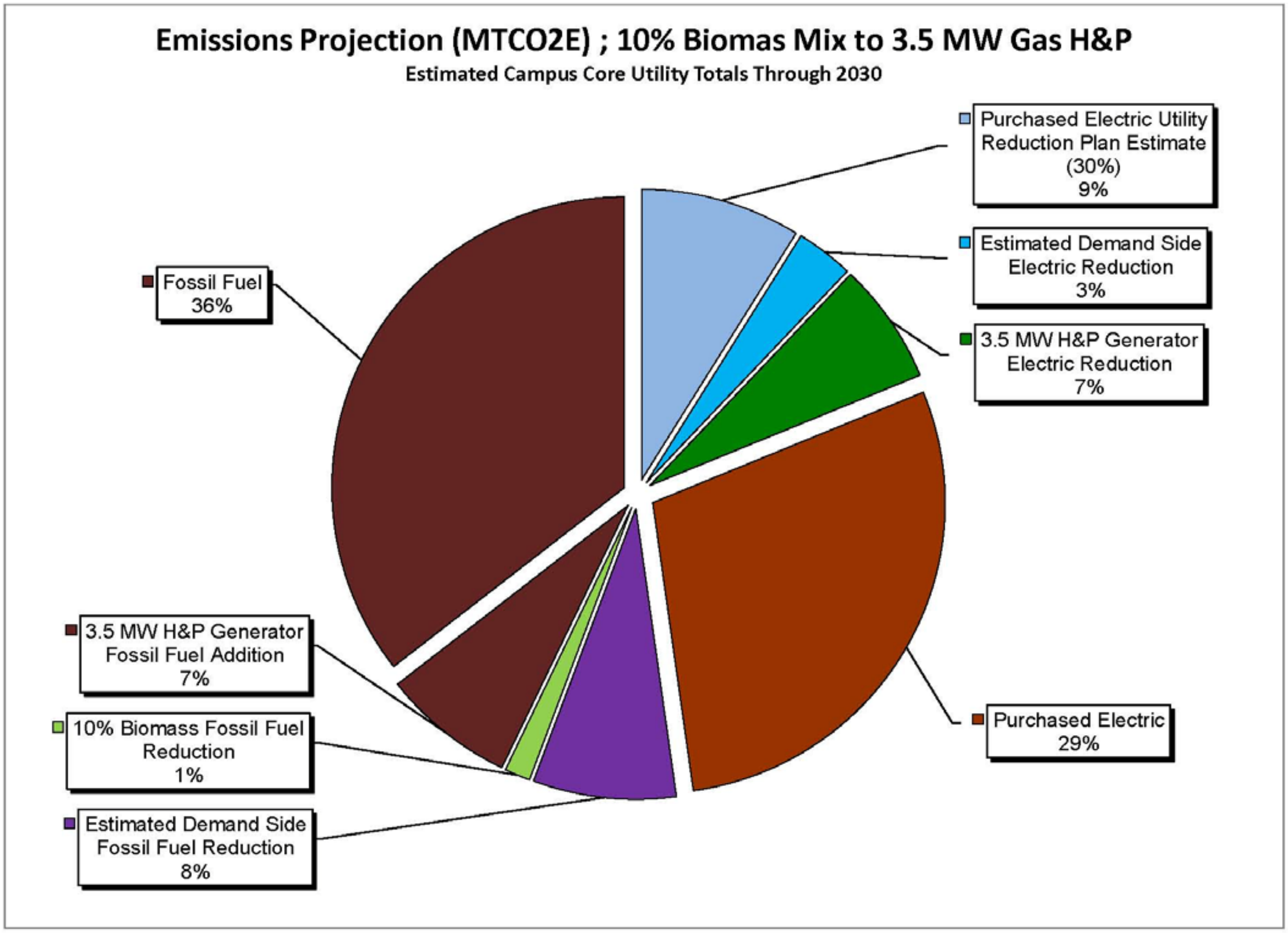


Figure IV-E-3-15



- **Reduction Option 7 – 3.5 MW 100% Biomass Heat and Power (H&P)**

  In the case defined in Figure IV-E-3-14a and Figure IV-E-3-15a the system evaluated is a combustion turbine with 100% biomass as the fuel. A complete reduction in fossil fuel is recognized in this case as well as a decrease in purchased electricity. This option requires further evaluation in relation to the technology and capabilities of the system to produce heat to satisfy campus loads.

Figure IV-E-3-14a

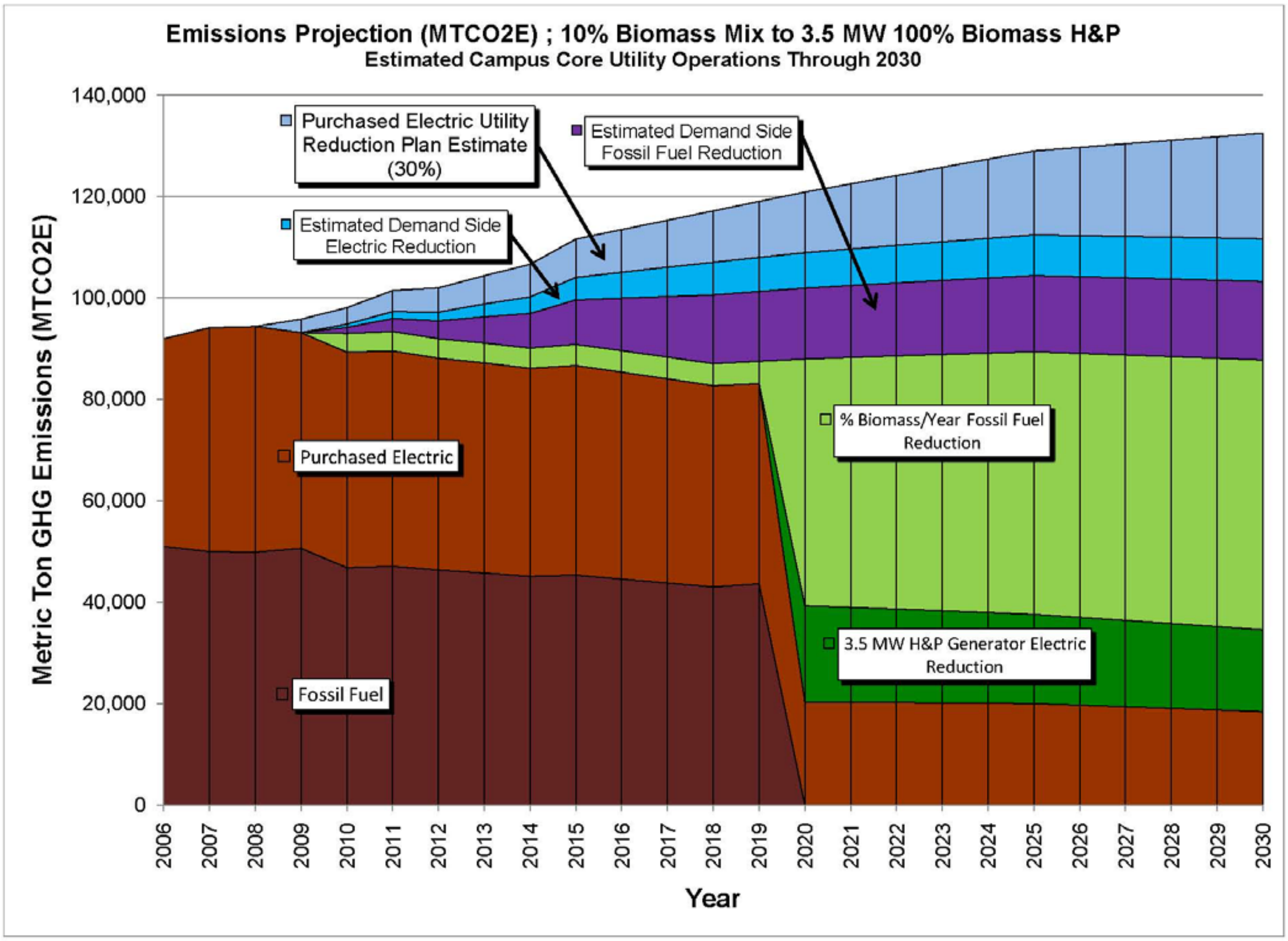
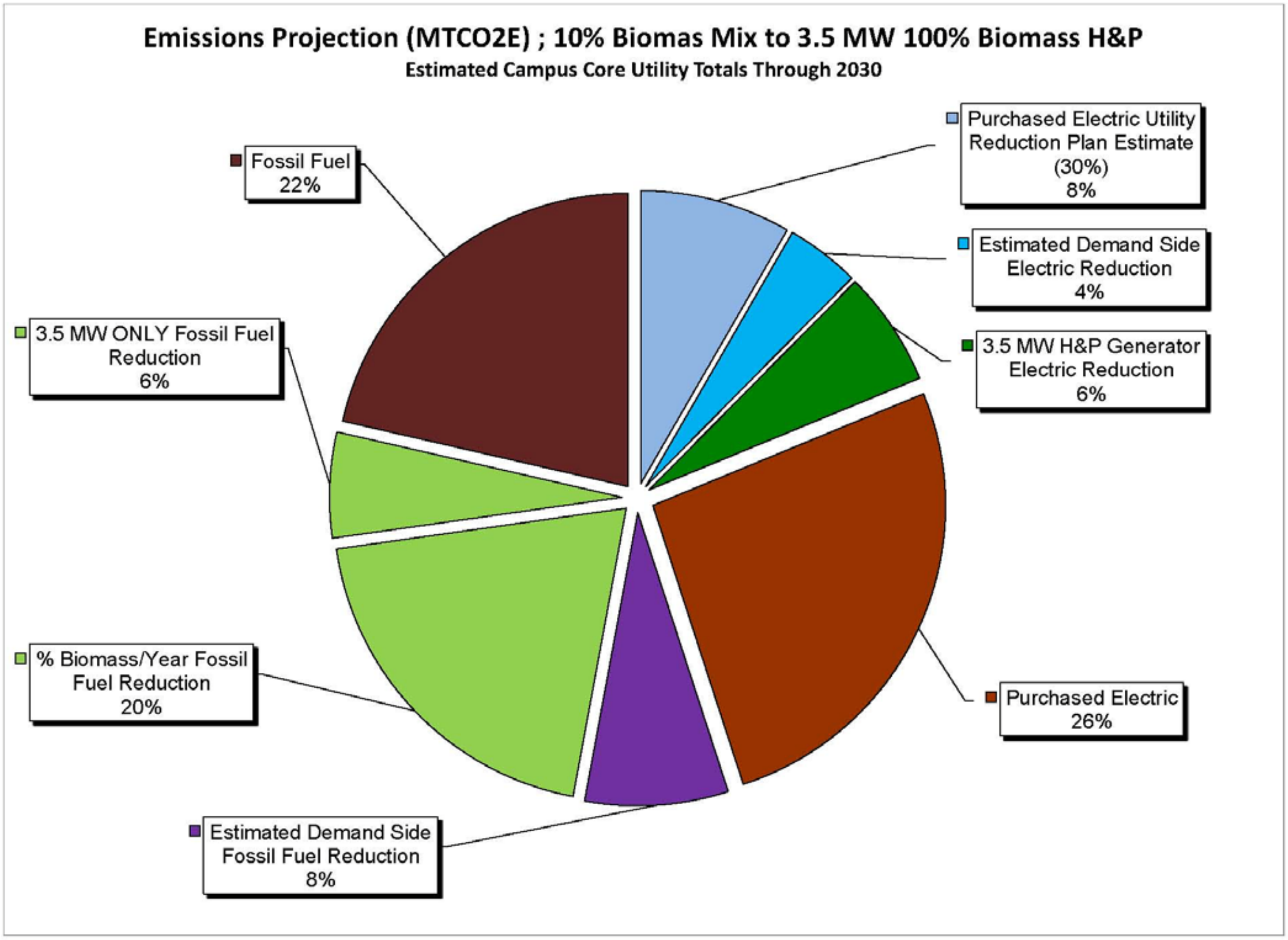


Figure IV-E-3-15a



- **Reduction Option 8 – 10% Biomass, 600 KW Backpressure Turbine**

  A second form of Heat and power generation is represented in Figure IV-E-3-16 and Figure IV-E-3-17 which shows the significance of emissions reduced due to the type of system utilized. For this case the system consist of a backpressure turbine applied at the CEP. Coal is utilized as the primary fuel to produce steam which in turn produces power. In this specific case the net reduction of the GHG are significantly less due to the increased quantity of coal fuel required to generate power. Since there is not reduction of GHGs from the fossil fuel, the credit available is only applied to the purchased electric utility.

Figure IV-E-3-16

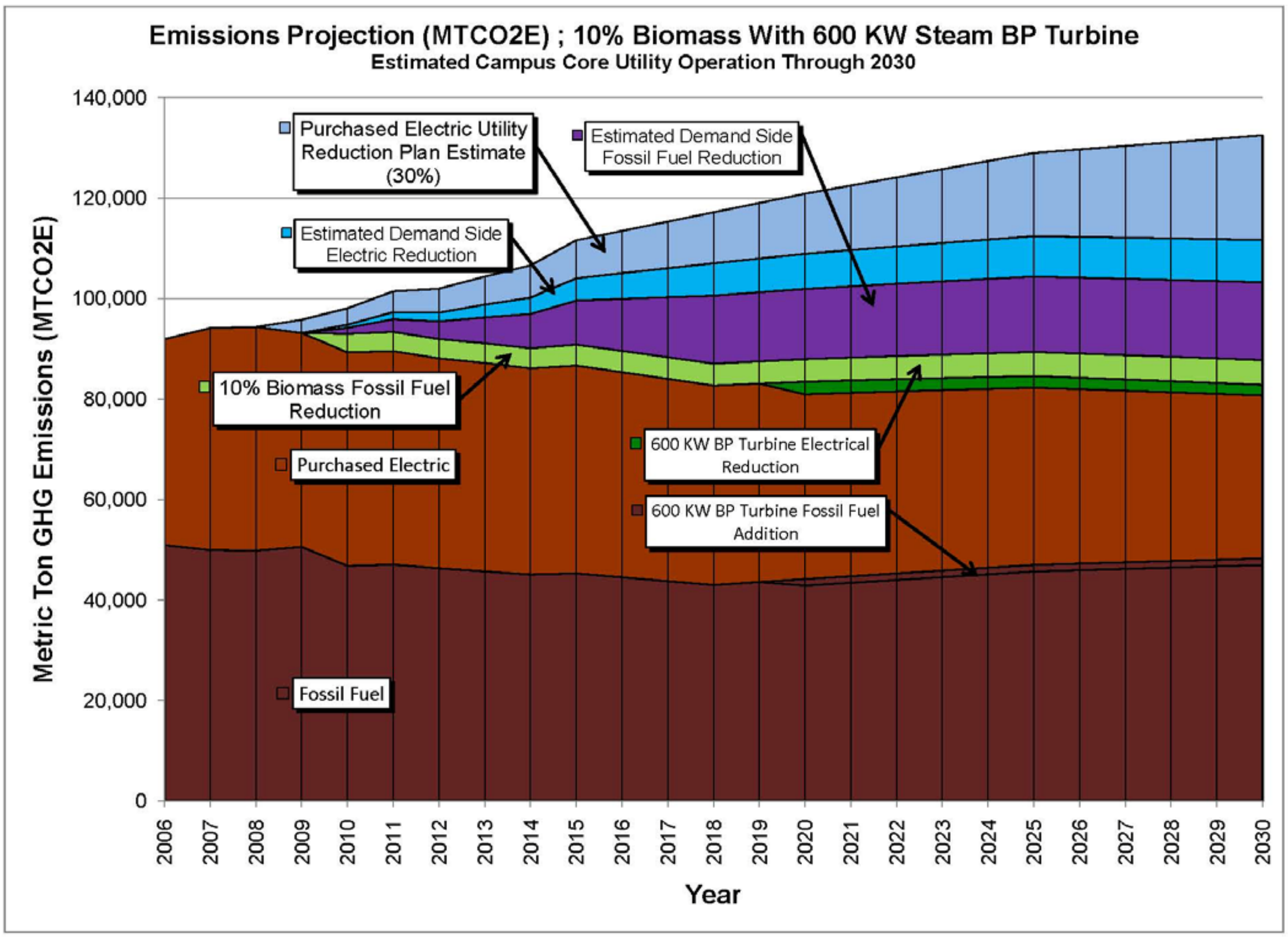
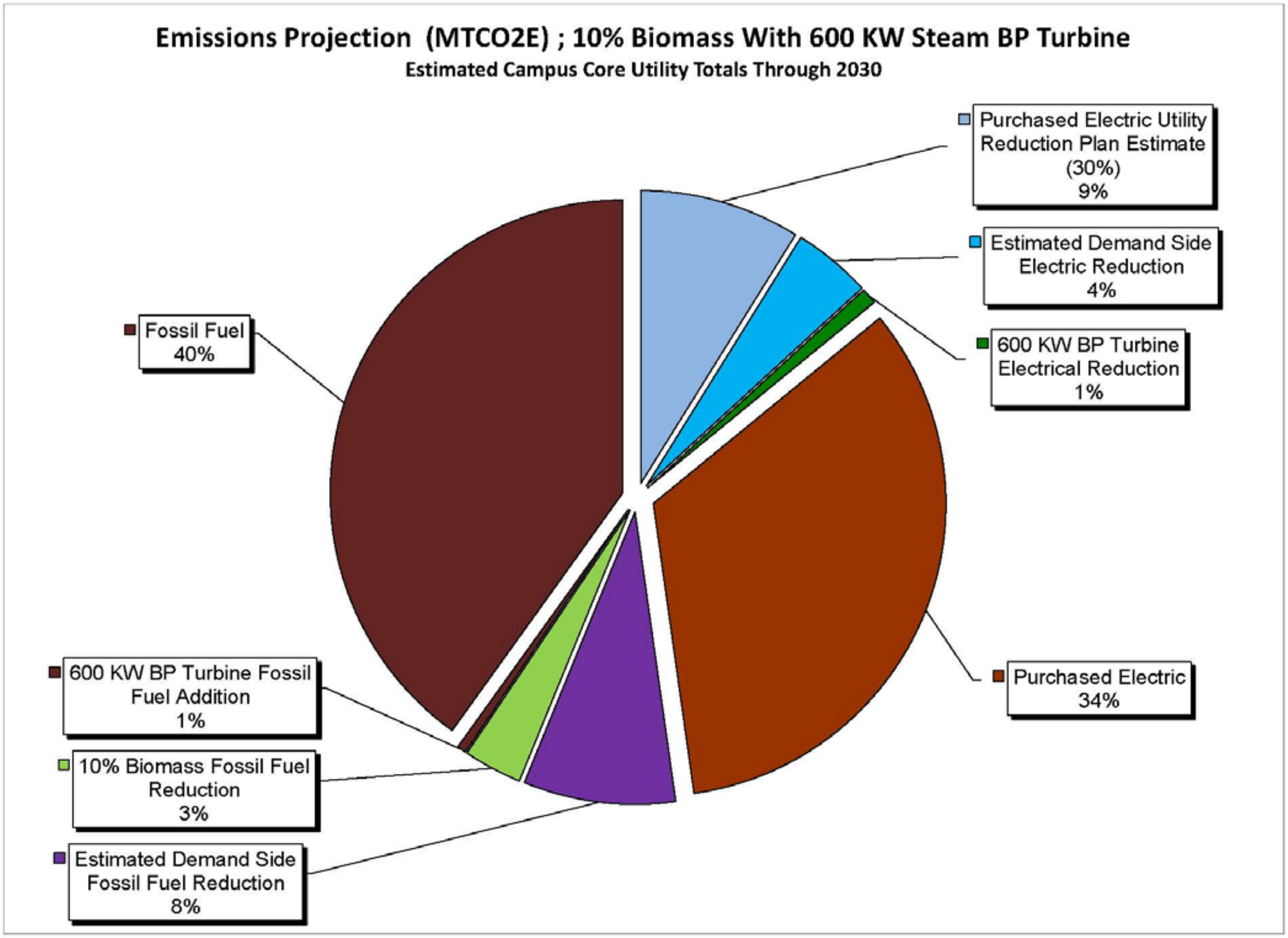


Figure IV-E-3-17



- **Reduction Option 9 – 600 KW Back Pressure Turbine Converting to 100% Biomass**

  Figure IV-E-3-16 and Figure IV-E-3-17 consist of a backpressure turbine applied at the CEP. Biomass is utilized as the primary fuel to produce steam which in turn produces power. In this specific case the net reduction of the GHG are significantly increased due to the complete reduction in fossil fuel as well as reductions recognized from electric production. This scenario requires further evaluation due to the capabilities of the existing boilers or new boiler in the future that burn biomass.

Figure IV-E-3-16a

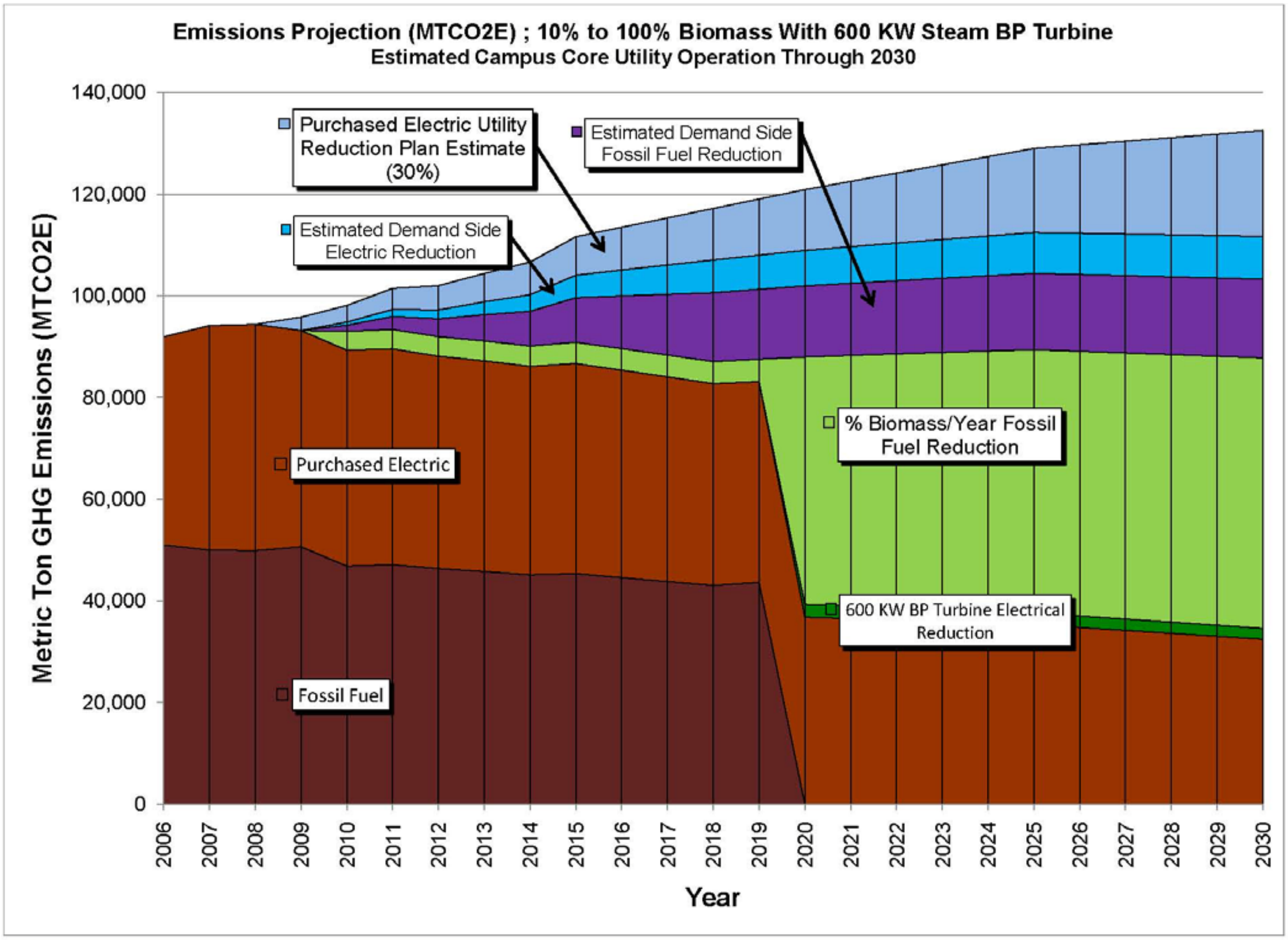
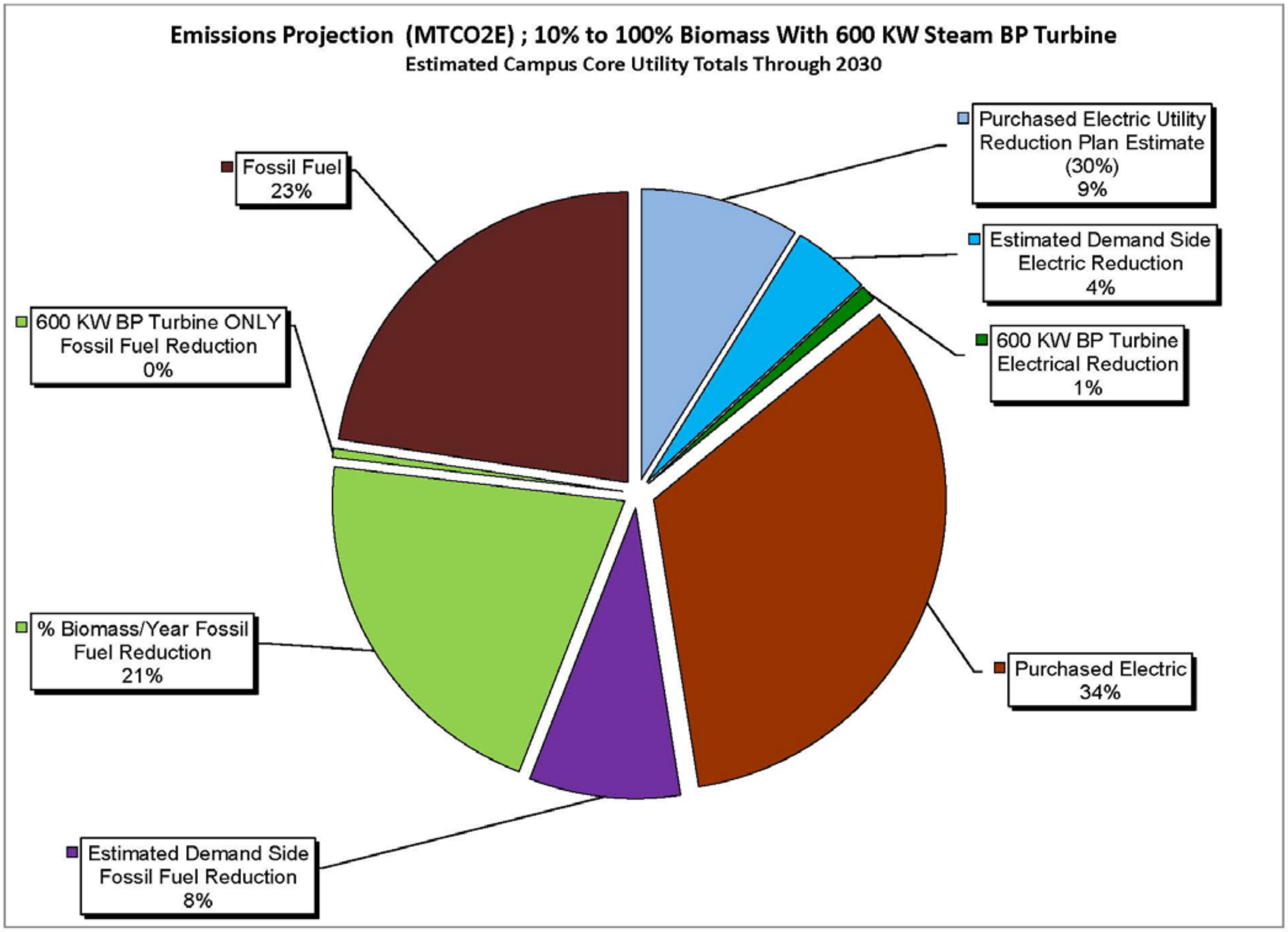


Figure IV-E-3-17a



- **Reduction Option 10 – 100% Biomass and 1.5 MW Wind Turbine**

  Introduction of wind turbines to supply power to the campus is a viable option due to the wind patterns seen at or near Laramie, Wyoming. The power produced form wind turbines or fields contain a net zero emission source that can be applied to the purchased electric utility.

  Figure IV-E-3-18 and Figure IV-E-3-19 represent a single 1.5 MW Wind turbine capability for emissions reductions. As seen in combination with biomass the net quantity of CO2 still represented on campus is significantly reduced by the biomass and still has potential for the purchased electricity.

Figure IV-E-3-18

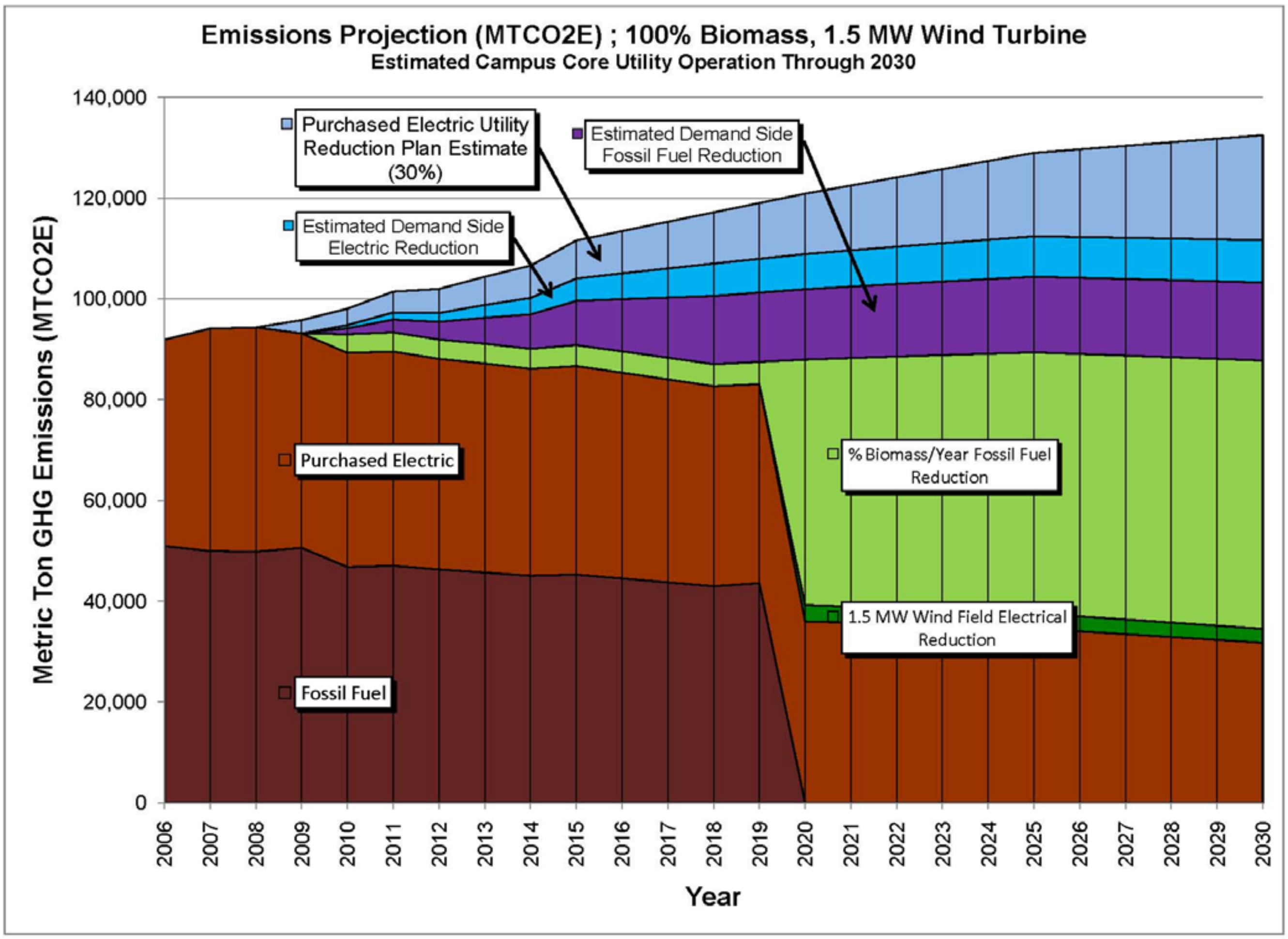
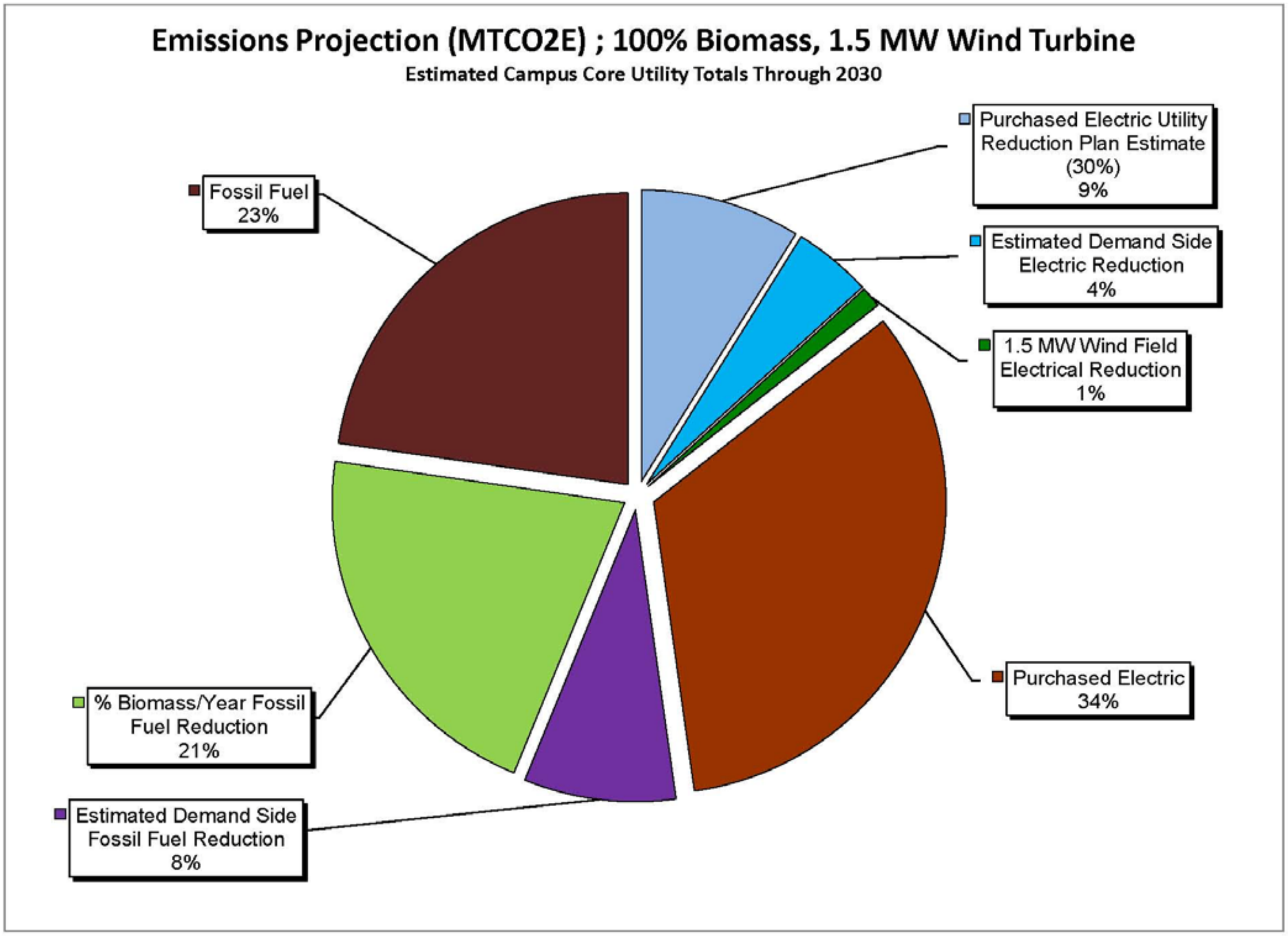


Figure IV-E-3-19



- **Reduction Option 11 – 100% Biomass and 15 MW Wind Turbine**

  Introducing additional electric capacity from wind turbines is shown in Figures IV-E-3-20 and Figure IV-E-3-21 which simply increases emissions reductions towards the purchased electric utility. As seen in combination with biomass the net quantity of CO2 is significantly reduced

  A second option to reduce purchased electrical emissions is through the purchase of renewable energy credits through which will accomplish the same affect if the power produced is indeed from wind generation. Under this case the utility provider would need to verify the credits can be utilized towards the campus reduction.

  Future evaluation in terms of economics and operations will be necessary to determine if this option is a viable area to consider emissions reduction for the campus. In lieu of Heat and Power, Wind or purchased clean power are the only options that significantly reduce the purchased electric utility without the need to purchase carbon tax credits for this source reduction.

Figure IV-E-3-20

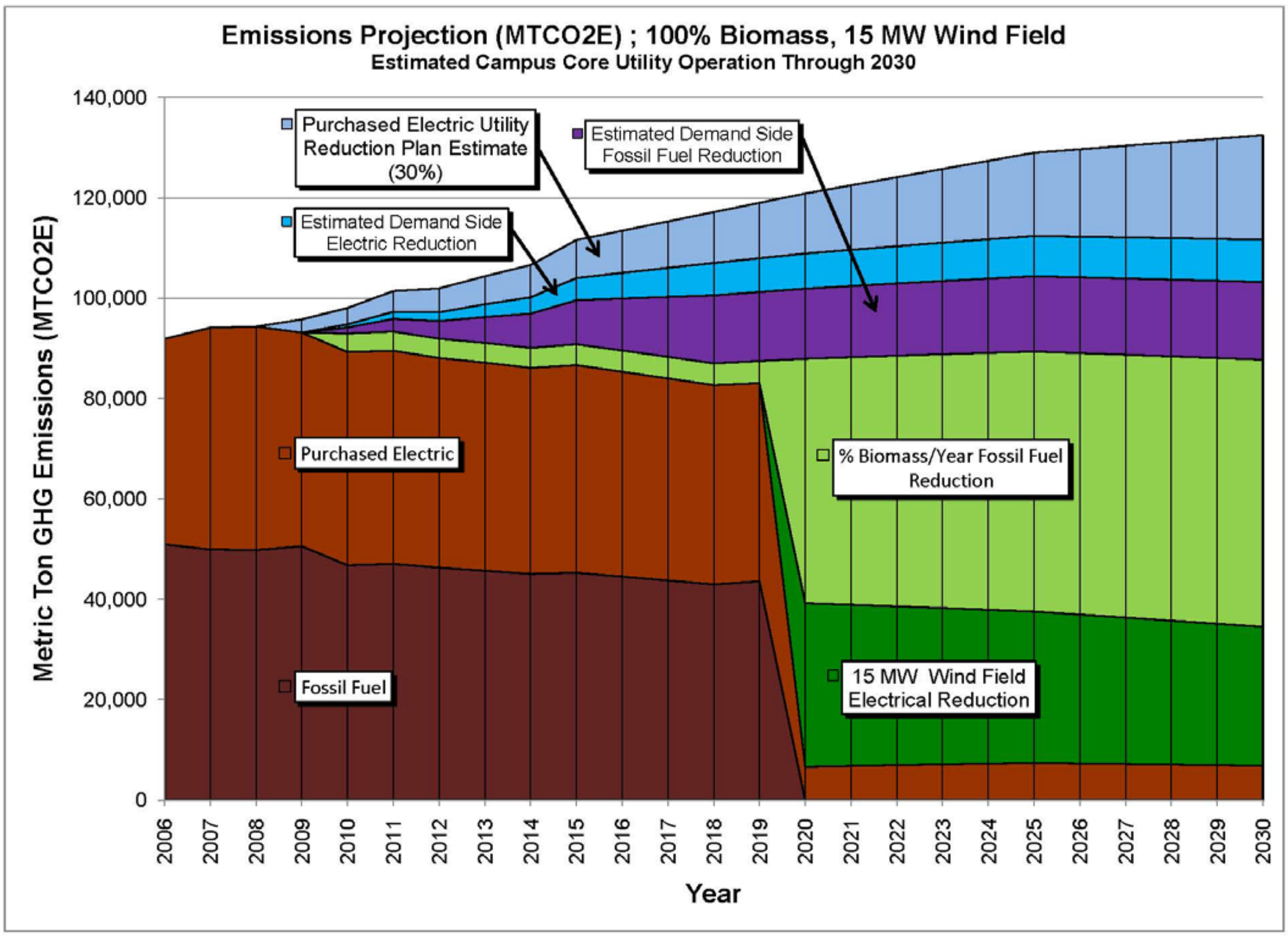
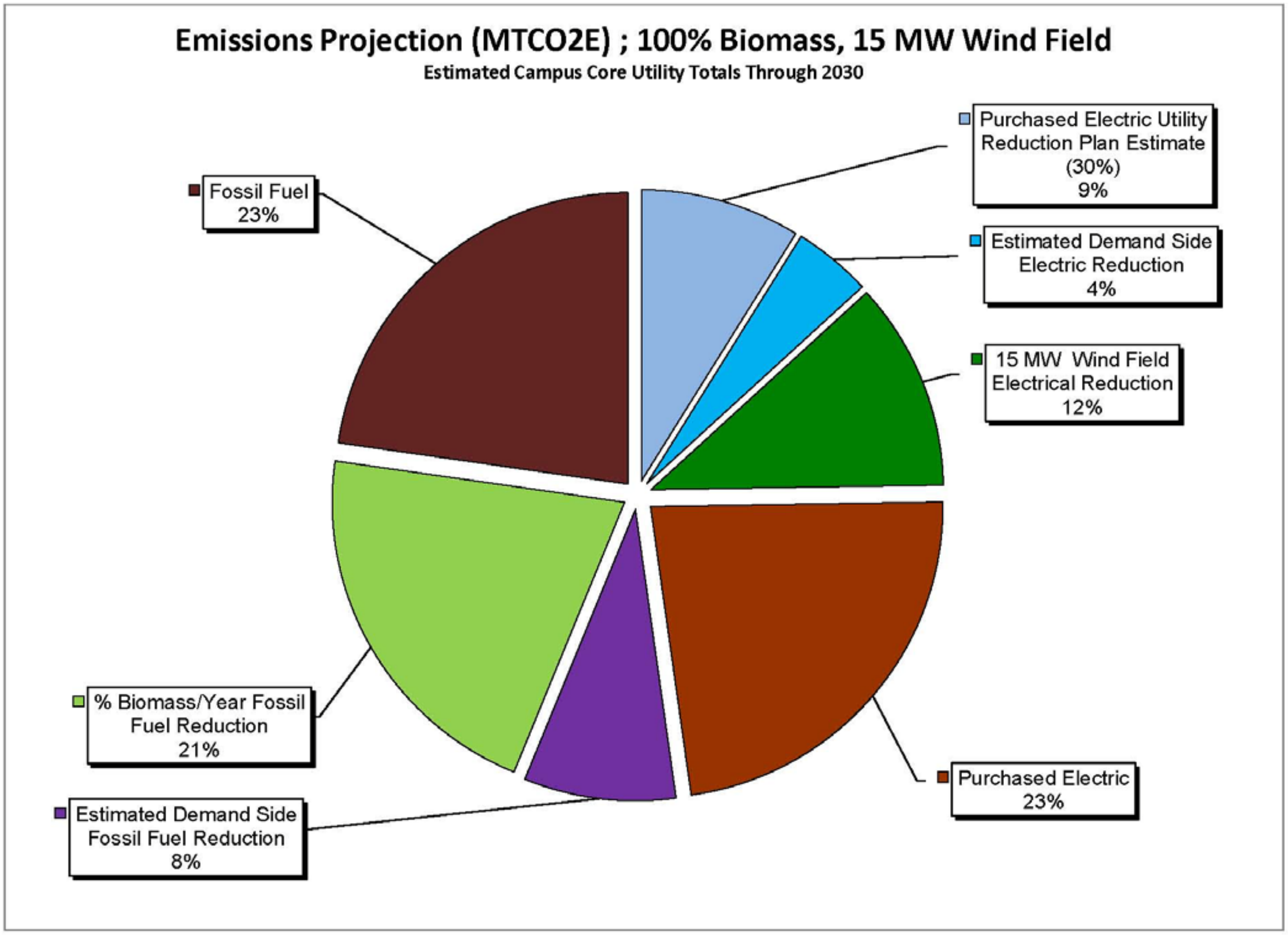


Figure IV-E-3-21



Further evaluation will also be required to determine how wind generated power and its service parallels the existing service.

4. Options Summary

The options identified above have been evaluated in terms of net reduction GHG emissions to the campus which can be utilized to understand the approach the campus wants to take to meet the American College and UW Presidents Climate Commitment (ACUPCC), signed and recently committed to by the UW. The commitment made by the UW is 15% GHG emissions reduction by year 2015 compared to year 2005, and 25% emissions reduction by year 2020 compared to year 2005.

Option Reduction # 5 appears to meet this guideline per estimated yearly reduction values as compared to historic year 2006 indicated in blue boxes within Table IV-E-3-3 in the appendix. The emission reduction from biomass fuel use and demand side reductions account for approximately 18% at year 2015 and approximately 75% at year 2020 based on MTCO2E. This percentage is only applied to the core campus utilities and full campus reduction efforts will be required to be evaluated. The reduction at year 2020 is significant due to the recommendation of converting to a boilers system capable of burning 100% biomass amongst other fuels.

A second part to the reduction analysis includes economic evaluation of the options noted above and is located in Tables IV-E-3-5 thru Table IV-E-16 within Appendix IV-E. Projected energy use for fossil fuel and electric are defined in Tables IV-3-5 and Table IV-E-3-6. These values are then applied to the appropriate fuel cost identified in Tables IV-E-3-7, 9, 11, 13, and 15. Carbon taxes are also represented in these tables in the red highlighted boxes. Carbon tax values are held constant in this evaluation and are based on MTC02E due to the unknown nature of the tax.

The resultant cost for each option and fuel use is indicated in Tables IV-E-3-8, 10, 12, 14, and 16. Values that change in color in the tables are related to revised electrical schedules, equipment expenditures and O&M for the year the option takes place. Equipment capital costs are defined in this table to approximate values of estimates identified for options within Section IV-B-C. The resulting dollar amount then recognizes a priority that can be placed toward each option. The Priority is based on the lesser dollar value expended in total at year 2030

To represent the changes that occur from carbon tax Tables IV-E-3-8, 10, 12, 14, and 16 include various carbon tax levels. This evaluation shows that the carbon tax has a significant effect on the priority of the options by the options shifting as the carbon tax increases. A comparison of priorities from $0 carbon tax to $80 of carbon tax is identified in Table IV-E-4-1 within Appendix IV-E.

Tables IV-E-3-8, 10, 12, 14, and 16 and various carbon tax levels are also represented by the figures herein. Each option yearly cost is identified by line work in comparison to one another. As shown in these figures the resultant cost shifts above or below one another when a carbon tax is imposed on the resultant MTCO2E projection. The lesser operating cost line would represent the option that has priority based on specific year and total expenditures thru year 2030.

Figure IV-E-4-1 below is a graphical representation in relation to Tables IV-E-3-7 and Table IV-E-3-8 within Appendix IV-E. The graph represents yearly cost of the options defined above which are based on the following estimated values:

- Zero Dollars ($0) Carbon Tax per resultant MTCO2E
- Demand side reduction capital cost and yearly energy savings.
- Fuel use which is based on natural gas, coal, or woody biomass as appropriate to the defined option.
- Electrical use which is based on Schedule 46 for current operations or schedule 33 for power production from H&P or Wind generation.
- Operation and Maintenance Cost.
- Capital for revised operations, equipment improvements and equipment additions.

Figure IV-E-4-1

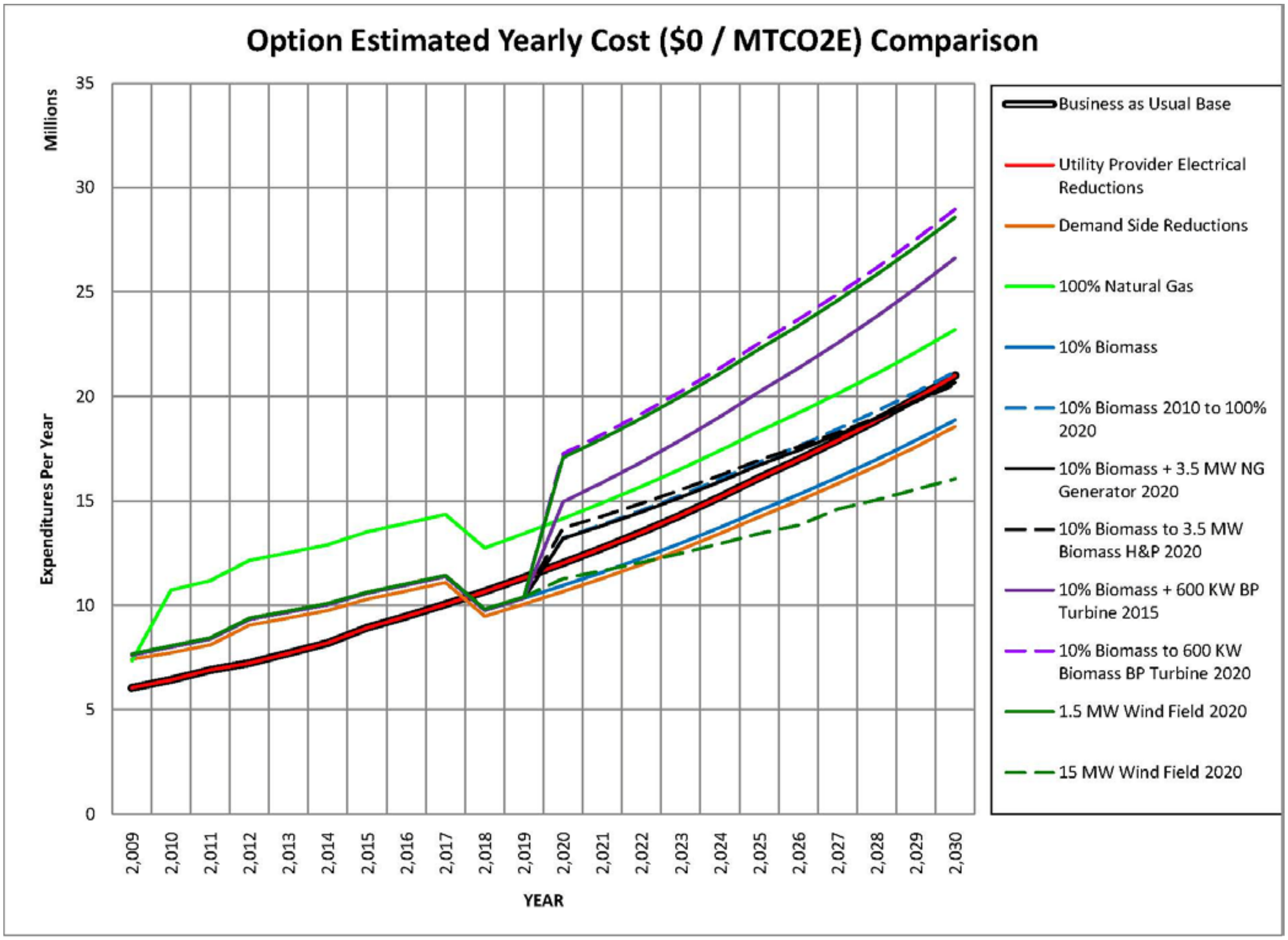


Figure IV-E-4-2 below is a graphical representation in relation to Tables IV-E-3-9 and Table IV-E-3-10 within Appendix IV-E. The graph represents yearly cost of the options defined above which are based on the following estimated values:

- Twenty Dollars ($20) Carbon Tax per resultant MTCO2E
- Demand side reduction capital cost and yearly energy savings.
- Fuel use which is based on natural gas, coal, or woody biomass as appropriate to the defined option.
- Electrical use which is based on Schedule 46 for current operations or schedule 33 for power production from H&P or Wind generation.
- Operation and Maintenance Cost.
- Capital for revised operations, equipment improvements and equipment additions.

Figure IV-E-4-2

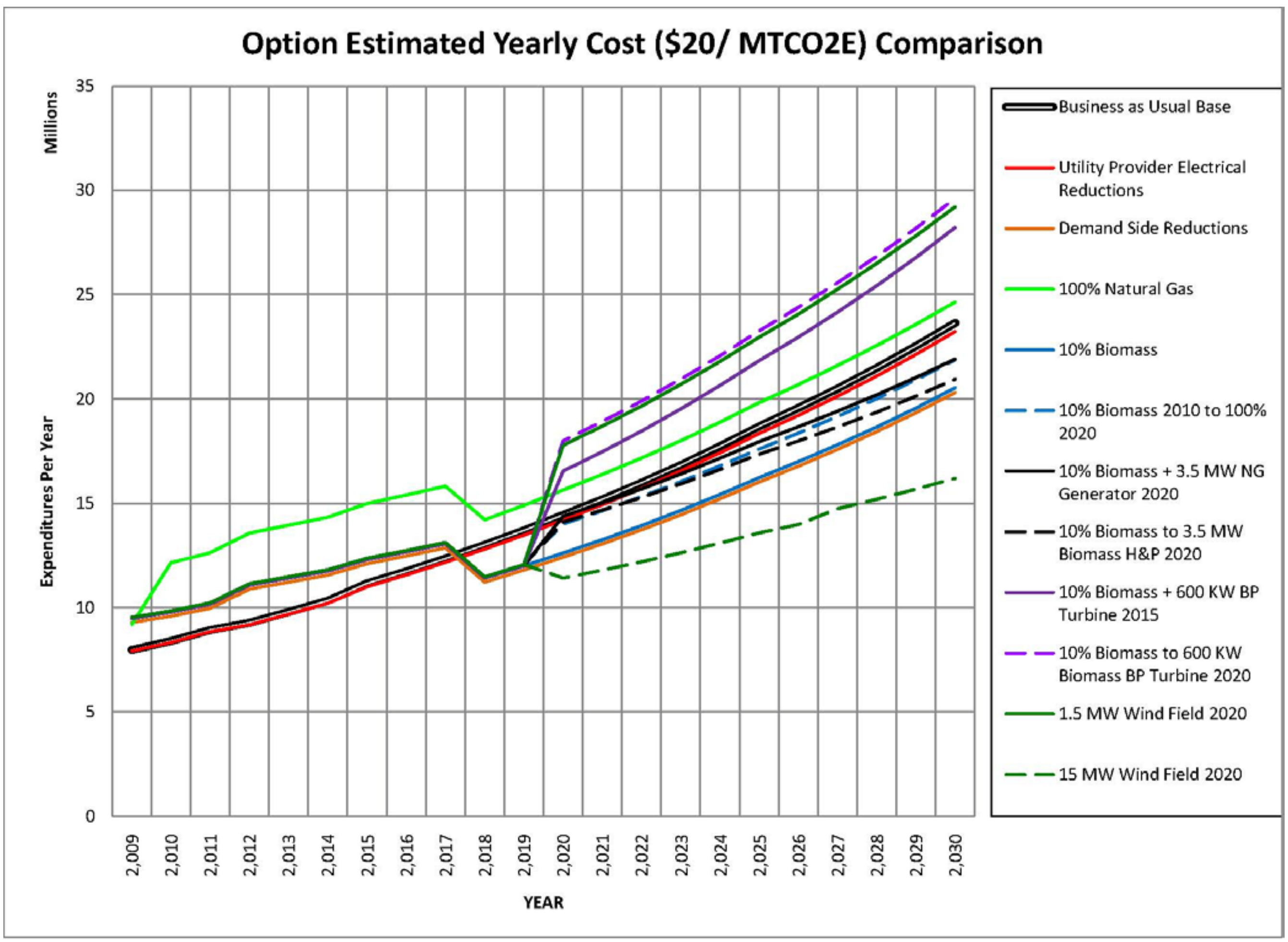


Figure IV-E-4-3 below is a graphical representation in relation to Tables IV-E-3-11 and Table IV-E-3-12 within Appendix IV-E. The graph represents yearly cost of the options defined above which are based on the following estimated values:

- Forty Dollars ($40) Carbon Tax per resultant MTCO2E
- Demand side reduction capital cost and yearly energy savings.
- Fuel use which is based on natural gas, coal, or woody biomass as appropriate to the defined option.
- Electrical use which is based on Schedule 46 for current operations or schedule 33 for power production from H&P or Wind generation.
- Operation and Maintenance Cost.
- Capital for revised operations, equipment improvements and equipment additions.

Figure IV-E-4-3

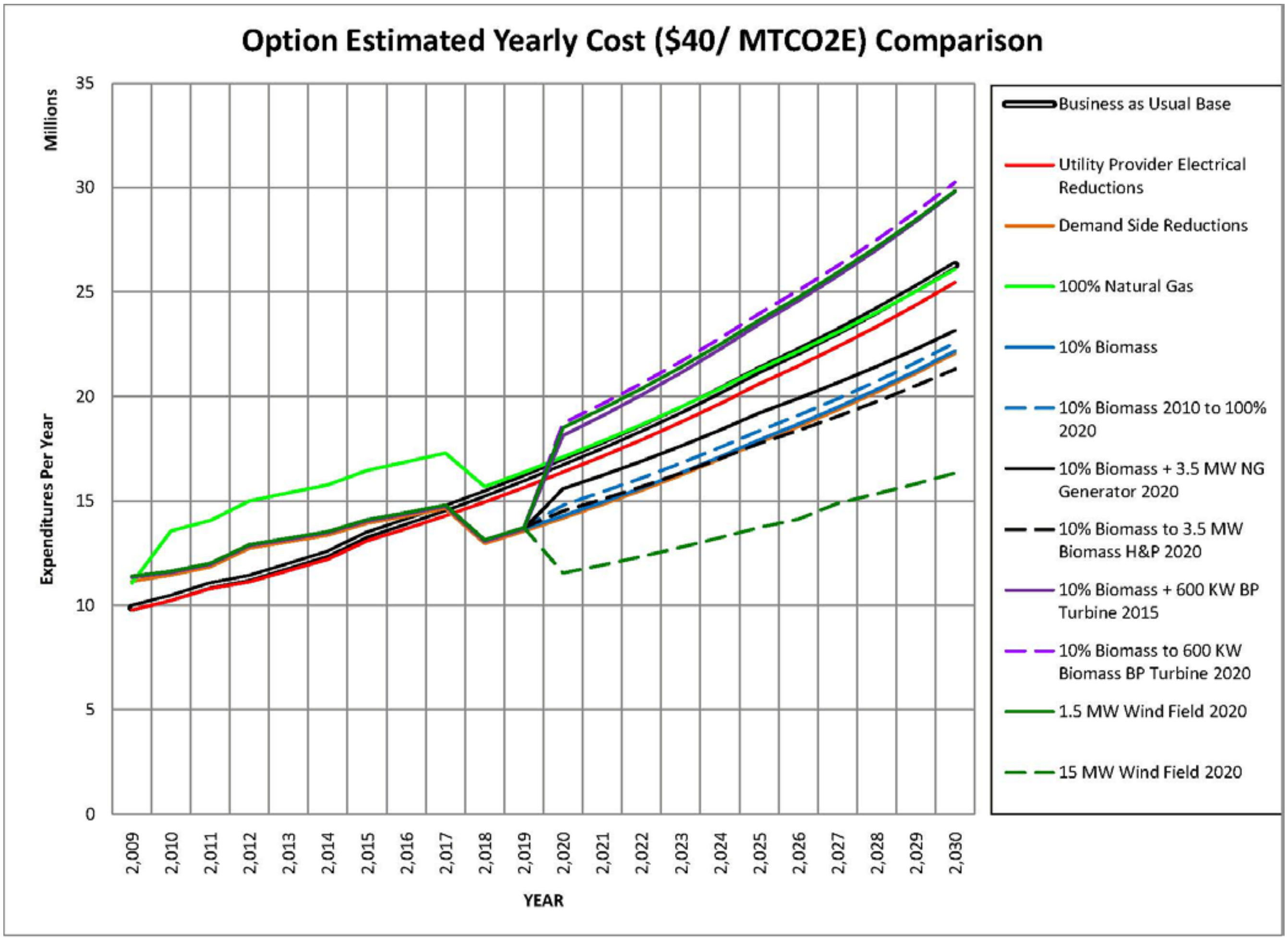


Figure IV-E-4-4 below is a graphical representation in relation to Tables IV-E-3-13 and Table IV-E-3-14 within Appendix IV-E. The graph represents yearly cost of the options defined above which are based on the following estimated values:

- Sixty Dollars ($60) Carbon Tax per resultant MTCO2E
- Demand side reduction capital cost and yearly energy savings.
- Fuel use which is based on natural gas, coal, or woody biomass as appropriate to the defined option.
- Electrical use which is based on Schedule 46 for current operations or schedule 33 for power production from H&P or Wind generation.
- Operation and Maintenance Cost.
- Capital for revised operations, equipment improvements and equipment additions.

Figure IV-E-4-4

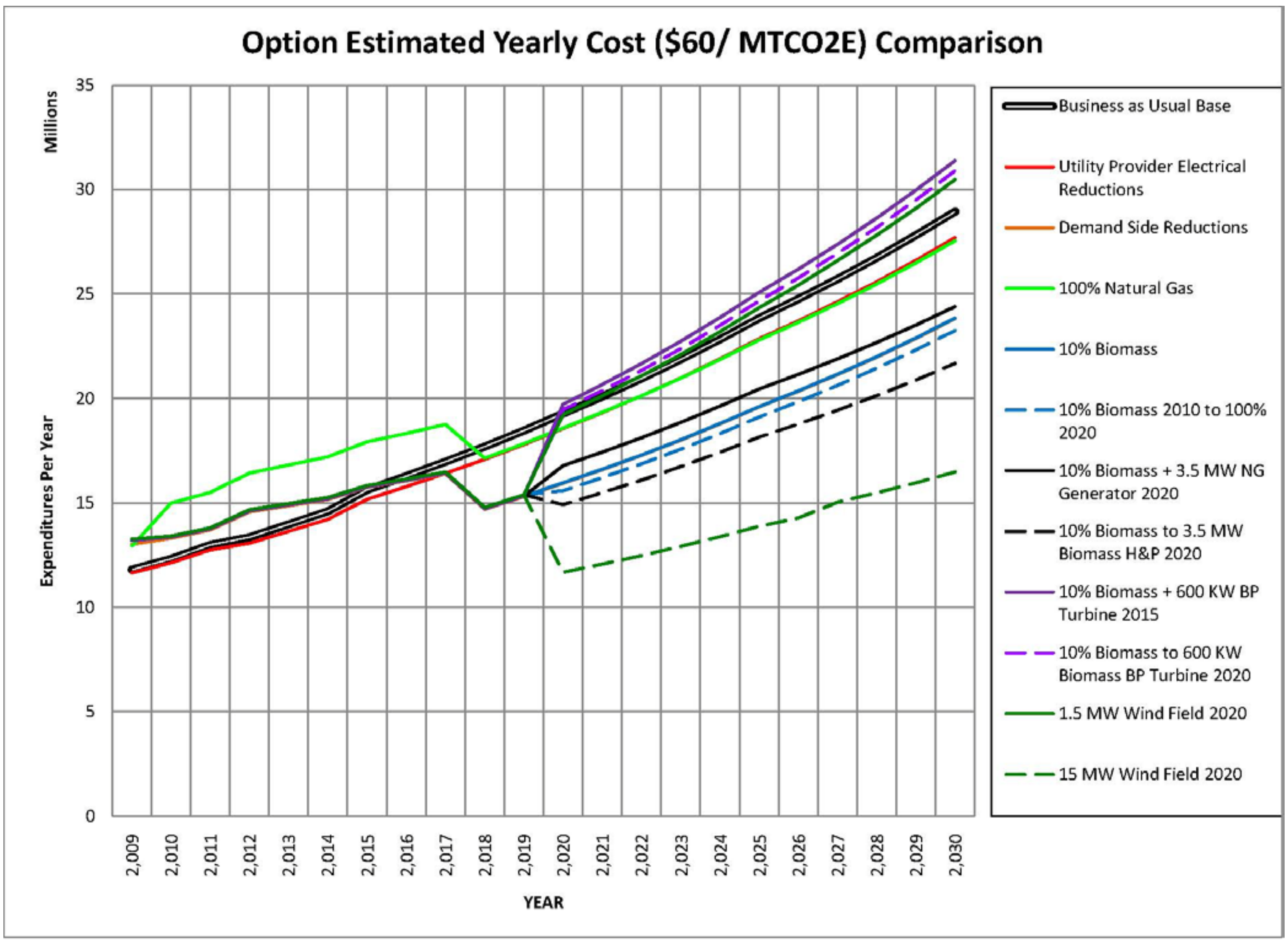


Figure IV-E-4-5 below is a graphical representation in relation to Tables IV-E-3-15 and Table IV-E-3-16 within Appendix IV-E. The graph represents yearly cost of the options defined above which are based on the following estimated values:

- Eighty Dollars ($80) Carbon Tax per resultant MTCO2E
- Demand side reduction capital cost and yearly energy savings.
- Fuel use which is based on natural gas, coal, or woody biomass as appropriate to the defined option.
- Electrical use which is based on Schedule 46 for current operations or schedule 33 for power production from H&P or Wind generation.
- Operation and Maintenance Cost.
- Capital for revised operations, equipment improvements and equipment additions.

Figure IV-E-4-5

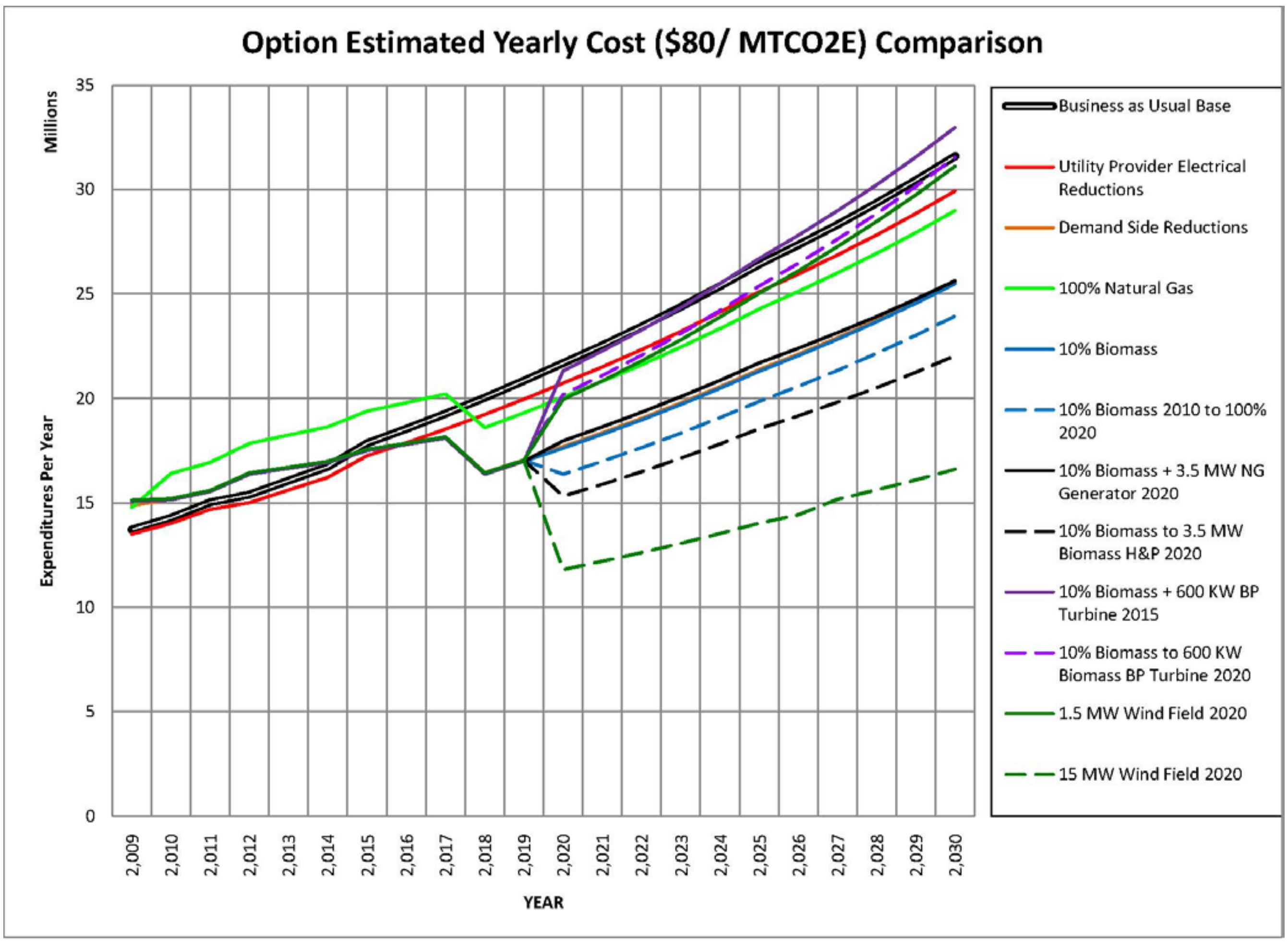


Table IV-E-4-2 is a comparison of the priority of options listed above for the carbon tax values presented at $0, $20, $40, $60 and $80.

Table IV-E-4-2

ANALYSIS OF OPTIONS BASED ON CARBON TAX 0$ Carbon Tax Represented	Option Above	COST Based on 2030 Total Dollars and Carbon Tax Input	Priority Based on Summaton of Priorities	PRIORITY BASED ON CARBON TAX AND BREAK POINTS — CARBON TAX QUANTITY $0	Priority Change $20	Priority Change $40	$60	Priority Change $80	Sum Used For Priority
15 MW Wind Field 2020	11	255,629,922	1	1	1	1	1	1	5
Demand Side Reductions	2	260,929,355	2	2	2	2	4	5	15
10% Biomass to 3.5 MW Biomass H&P 2020	7	293,402,083	3	8	4	3	2	2	19
10% Biomass	4	267,202,828	4	3	3	4	5	4	19
10% Biomass 2010 to 100% 2020	5	293,236,768	5	7	6	5	3	3	24
Utility Provider Electrical Reductions	1	271,462,571	6	4	5	7	7	7	30
10% Biomass + 3.5 MW NG Generator 2020	6	290,289,879	7	6	7	6	6	6	31
Business as Usual Base	0	271,462,571	8	5	8	8	8	12	41
100% Natural Gas	3	337,546,290	9	10	10	9	10	10	49
1.5 MW Wind Field 2020	10	353,599,299	10	11	11	11	9	8	50
10% Biomass + 600 KW BP Turbine 2015	8	330,408,353	11	9	9	10	12	11	51
10% Biomass to 600 KW Biomass BP Turbine 2020	9	356,664,490	12	12	12	12	11	9	56

Priority 1-3 Based on Carbon Tax Input
Priority 4-6 Based on Carbon Tax Input
Priority 7-9 Based on Carbon Tax Input
Priority 10-12 Based on Carbon Tax Input

As previously defined above in section B the recommended action of burning a percentage of Biomass per weight until year 2020 and then conversion to 100% biomass with the addition of a boiler appears to fall within the range of an applicable recommendation based on priorities.

Wind Production will need to be evaluated further pending the Universities commitment to operate the system. 100% Biomass Heat and Power will require further evaluation based on technology advancement.

The introduction of H&P and Wind electrical power generation on campus will need to consider revised electrical schedules through Rocky Mountain Power. Currently the UW is under schedule 46. When power generation of any form is introduced, and a backup source of energy is required from RMP, the schedule is updated to 33 which increases the value of the electricity purchased under normal conditions. A demand peak is required to hold this value which is negotiated through RMP. If the demand negotiated is short on failure of either power system, the penalties imposed are fairly significant and are understood to be applied after and through the remainder of the year. The demand should be estimated and negotiated if any power conversion takes place and tweaked lower as required through analysis of following year operation. Access and identification of the applicable power schedules for Rocky Mountain Power can be found on the Internet at www.rockymountainpower.net and are located under the path, customer service, rates and regulation, Wyoming, Schedules.

F. Electrical

1. General Overview

The options available with regard to distribution concepts are directly related to potential feeder routing and interconnection configurations. In lieu of adding new service systems independent of existing systems, reconfiguring the West and East distribution systems plus incorporation of existing loads into new system geometry presents greater possibilities involving and impacting both the new and old systems. This approach builds a higher degree of flexibility and options for future development of facilities without having the electrical systems become a limiting factor.

Relocation of existing feeders to clear new building construction can serve to also create opportunities to expand electrical system flexibility, while more directly keeping development programs on track. By keeping the primary system as a major consideration in campus development, planning efforts can result in an improvement to all of the campus load characteristics. In keeping rate structures from the electric supplier (RMP) as an essential factor, the building design efforts may dictate keeping the load characteristics as close as possible to existing levels.

2. Summary

Keeping flexibility at the forefront of design can serve to keep building expansion options and opportunities open.

G. Domestic Water

1. General Overview

The existing UW campus lies within the City of Laramie and City potable water distribution system Pressure Zone 2. As a result, potable water on campus is provided by gravity from the Zone 2 above-ground water tanks that are located on a ridge immediately east of campus. With the possible exception of a small area located north of Lewis St. and immediately east of 9th St., areas of anticipated future campus expansion will also lie within City Pressure Zone 2. Description and hydraulic modeling output pertaining to the existing campus potable water distribution system are contained in report Section II.F and Appendix II-F-4. Description and hydraulic modeling of proposed future campus water distribution system growth are included in report Section III-F and Appendix III-F-1.

The existing campus potable water system has historically functioned satisfactorily under typical operating conditions. In the absence of major structure fires on campus during the recent past, actual fire flow discharge capacities at campus fire hydrants is unknown, as are the impacts of interaction between building sprinkler systems and fire hydrant fire flows. Hydraulic modeling completed during this project indicated that hydrants on much of the existing campus are incapable of providing satisfactory theoretical fire flows. This assumed problem is based primarily on the existence of under-sized water mains in much of the core campus as well as in the student housing area.

2. Options Evaluation

Available options for modifying and expanding the existing campus potable water distribution system to improve campus fire flow availability and to provide for adequate fire flows for future campus development include:

- Replacing all or sections of approximately 22,700 linear ft of existing 6" campus water line in the main part of campus (not including the student housing area, which will be re-developed) with new 10" water line as shown on WaterCAD® maps for Scenarios DF-4 and DF-5 in Appendix III-F-1 in order to improve campus fire flow capacities:

  Recommended replacement of existing 6" water lines with 10" water lines is based on assessment of modeled campus fire flows under existing conditions. This recommendation may or may not be considered a high priority by UW based on the level of risk that UW wishes to accept regarding potential campus structure fires and the impacts of other factors, such as building sprinkler systems and the availability of proper firefighting equipment, on campus fire fighting capabilities.

- Constructing five new 10" diameter water line loops to serve future development as shown on future conditions WaterCAD® modeling maps in Appendix II-F-1; these proposed lines would provide new looped water lines between existing water mains of the same or larger diameter:

  Recommended construction of new 10" or larger diameter water line loops is based on assumed future campus development and the assumed desire to provide adequate theoretical fire flows for this development. Existing City and campus water distribution lines are likely inadequate to support this development. This recommendation is therefore probably not optional.

- Installing building water meters in each new or remodeled building:

  This relatively inexpensive recommendation would provide UW staff with building water demand data so that locations of unusually high demand could be determined and water conservation measures could more efficiently be installed and maintained. The City of Laramie cost for a 1": interior water meter and appurtenances is currently $742.00.

- Expand the existing campus master water meter system to cover areas of future campus development:

  Implementation of this recommendation would both maintain simplified City reading and UW maintenance of overall campus water metering.

3. Options Summary

Options for improving the existing campus potable water distribution system and for expanding the system to provide adequate fire flows for future campus development include replacing existing 6" diameter campus water mains with 10" diameter mains and installing new 10" diameter water mains in areas of assumed future campus development. Proposed installation of 10" diameter new and replacement water lines was based on WaterCAD® modeling of fire flow demands and the goal of providing adequate fire flow and pressure at all appropriate demand nodes. Replacing older existing 6" water lines on campus could also reduce water losses through leakage since older cast iron water pipes in other parts of Laramie have exhibited significant deterioration over time. The estimated unit cost for designing and installing new 10" diameter water lines is $178 per linear ft.

Table IV-G-1 below contains a summary of recommended water distribution system modifications and enlargements. Note that the unit cost for new 10" diameter water mains is in 2009 dollars and includes costs for removing and replacing existing pavement, costs for installing fire hydrants at 400 ft intervals, costs for valves and fittings, an amount equal to 25% of the base estimated construction cost to cover contingency and mobilization/demobilization, and an engineering cost estimate equal to 20% of the base estimated construction cost. Replaced 6" diameter water lines would presumably be abandoned in place. A work calculation spreadsheet showing derivation of these estimates is included in Appendix IV-GHIJ-1.

Table IV-G-1 – Summary – estimated engineering and construction costs – new potable water mains.

Item no.	Description	Unit	Estimated quantity	Estimated unit cost	Estimated total cost
1	10 inch diameter PVC replacement water line	lf	22,700	$ 178	$4,040,600
2	10 inch water line – Flint Street loop	lf	3,500	$ 178	$ 623,000
3	10 inch water line – Ivinson/Grand loop	lf	2,300	$ 178	$ 409,400
4	10 inch water line – Gibbon Street extension	lf	1,600	$ 178	$ 284,800
5	10 inch water line – 22nd Street loop	lf	3,100	$ 178	$ 551,800
6	10 inch water line – student housing loop	lf	4,000	$ 178	$ 712,000

H. Irrigation System

1. General Overview

As described in report Section II-G, the existing campus irrigation distribution system is complex and neither fully understood nor documented. Irrigation system operation is based primarily on operator experience and trial-and-error. The existing system appears to function adequately based on the lush appearance of landscaped areas of the campus in the cool, dry Laramie environment. Current operation of the campus irrigation system with water from a single campus water well results in significant risk to the system should this well fail or become inoperable for a significant period of time.

2. Options Evaluation

Options for future work pertaining to the campus irrigation system include:

- Using the results of this study as a base, completing a more detailed study, including preparing detailed maps, describing all components of the existing campus irrigation systems so that mapping is complete and accurate, executing more refined system hydraulic analyses, and developing system operating standards that apply to the entire campus:

  The option of continuing and expanding the mapping and documenting of the existing campus irrigation system should be a high priority. Completion of this work should support future design, expansion, and operation of the campus irrigation system in a more systematic, efficient, and cost-effective manner.

- Permitting and constructing one or two additional campus irrigation system water supply wells in order to avoid current reliance on the existing water well that is located near the Fine Arts Building:

  Permitting and constructing one or two additional campus irrigation water wells should move forward. Reliance on a single irrigation system water supply well results in significant risk should that well fail or discharge from that well be interrupted for a significant period of time. While part or all of the campus irrigation system may be supplied from the City water distribution system on a short-term basis, the transition to City water could be time consuming and expensive and could result in inefficient use of potable water for irrigation purposes.

- Expanding the existing campus irrigation system to cover areas in which future campus expansion is anticipated:

  Expanding the existing the campus sprinkler irrigation system to cover areas of future development is not optional given the UW tradition of maintaining attractive campus landscaping in a relatively harsh environment. Future irrigation system expansion will presumably occur in stages concurrently with campus expansion. It should be noted that installation of turf irrigation systems is typically completed in conjunction with building construction or renovation. A significant portion of future costs of expanding the existing campus sprinkler irrigation system may therefore be included in future building construction or renovation budgets.

- Purchase and operate a campus-wide irrigation system SCADA (supervisory control and data acquisition) system:

  Implementing this recommendation following completion of the campus irrigation system study that is recommended above should provide centralized, efficient, and consistent campus irrigation. The specific nature and components of this system should be determined using the results of the irrigation system study

- Completing a study focused on possible use of other campus sources of irrigation water supply, such as roof drains and building sumps.

  UW currently pumps significant quantities of groundwater from campus building foundations and basements. This water is discharged into the campus storm water collection system. Examples of significant average quantities of water pumped from building sumps include:

- Fine Arts -6.9 gpm;
- Law – 5.6 gpm;
- Arena – 34.7 gpm;
- ITF – 27.8 gpm;
- Anthropology – 24.3 gpm; and
- Other buildings – 16.7 gpm.

This combined discharge of approximately 116 gpm represents approximately 25% of the current output of the Fine Arts irrigation water well.

In addition, roof drains from campus buildings convey significant though intermittent quantities of rain water to the campus and City of Laramie storm water management systems. Either or both of these sources of water supply could be utilized to supplement the existing campus irrigation water supply and could serve as an environmentally sound campus operation. The cost of doing so, however, may be prohibitive.

3. Options Summary

Proposed options pertaining to the campus irrigation system are summarized in Table IV-H-1 below. A work calculation spreadsheet showing derivation of these estimates is included in Appendix IV-GHIJ-1. Each cost estimate was prepared based on 2009 dollars and typically included engineering and related professional service costs as well as a 25% contingency. Since turf irrigation costs are typically included in building construction or remodeling costs, cost estimates for future campus turf irrigation are not included in this table.

Table IV-H-1 – Summary – estimated engineering and construction costs – Irrigation System Improvement and Expansion

Item no.	Description	Unit	Estimated quantity	Estimated unit cost	Estimated total cost
1	Study, report, and mapping – existing irrigation system	ls	1	$ 93,000	$ 93,000
2	New irrigation water well	ea	1	$ 762,000	$ 762,000
3	Extended irrigation mains – 3 in, 4in, and 6 in	lf	13,700	$ 48	$ 657,600
4	Study – alternative sources of irrigation water supply	ls	1	$56,500	$56,500
5	Irrigation SCADA system – 2 water wells, 100 controllers, 15 zones per controller (1,500 zones, total)	ls	1	$ 1,337,000	$ 1,337,000

Note the following regarding the cost estimates shown above:

- The irrigation study, report, and mapping cost estimate includes engineering, surveying, and map and document preparation;
- The new irrigation water well was assumed to be 700 ft deep, and the total estimated costs includes geology work, engineering, and permitting
- Lengths of extended irrigation water lines for 3”, 4”, and 5” diameter lines were taken from the future conditions WaterCAD® model; the $48 per linear ft unit cost is a composite value based on calculated construction costs for each of the three pipe diameters and lengths.

I. Storm Sewer System

1. General Overview

The UW storm water management system consists primarily of catch basins and pipelines that are intended to convey storm water from campus into the City of Laramie storm water collection and discharge system. Several storm water detention and retention ponds are also located on campus. This study included research, field surveying, and preparation of a map and descriptive spreadsheet accurately describing campus storm water facilities. In addition, the hydrology of known storm water management problem areas was assessed along with the hydraulics of adjacent storm water pipelines. Hydrologic analyses of areas within and near the campus within which future campus expansion is anticipated were also completed in order to determine changes in peak storm water runoff rates that may occur as a result of future development. This study and report have therefore provided a sound basis for continued, more detailed work that could be the used during design and construction of modified and new campus storm water management facilities.

2. Options Evaluation

Options available to UW regarding storm water facilities that were developed during this study included:

- Completing a detailed assessment, using information from this report as a base, of catch basin inlet capacities in order to determine whether conclusions that are included in this report regarding the ability of existing storm sewer management pipelines, including those on Willett Drive and on 15th St. between Willett Drive and Grand Avenue, to safely convey the required quantity of storm water runoff:

  The hydrologic and hydraulic study of the Willett St. basin and the 15th St. storm sewer system indicated that the 15th St. storm sewer system should be capable of conveying runoff from the Willett St. basin. This analysis did not include assessment of the inlet capacities of existing 15th St. catch basins. Since existing storm sewer pipelines may be capable of conveying higher flows than catch basins can collect and discharge into the pipelines, this proposed study should either confirm the conclusions in this report regarding the status of this system or lead to design and installation of additional and/or improved catch basin grates to allow the 15th St. storm sewer system to perform to capacity.

  The cost estimate below includes surveying and engineering analysis as well as assumed installation of eight new catch basins on existing Willett Drive and 15th St. storm sewer lines.

- Completing site surveys, preparing topographic maps, delineating smaller drainage subbasins, and completing detailed hydrologic and hydrologic analyses of the Arena Auditorium/Law Building drainage basin (Basin B33) and the Arts and Sciences/Physical Sciences basin (Basin B3) in order to properly assess existing storm water management in these areas and to determine the need, if any, for improvements to existing storm water management facilities:

  Hydrologic studies of basins B3, Arts & Sciences north, and B33, Arena – south and east that were completed during this project were based on available topographic and mapping detail. The available level of detail is inadequate to assess hydrology and pipeline hydraulics in and downstream of these basins. Acquisition of more detailed survey data would allow division of these basins into smaller subbasins, thereby supporting a more detailed hydrologic and hydraulic analysis of the areas and the existing storm water management facilities that are located in and downstream of the basins. This more detailed analysis could then lead to design and construction of improved storm water management facilities, if required, in either or both of these areas.

  The cost estimate shown below includes surveying and engineering analysis only since the nature and extent of future drainage improvements are not possible to predict at this time.

- Re-designing storm water management facilities for the Football stadium/parking lot basin (Basins B43 and B44) and replacing retention Pond B43/44:

  Basins 43 and 44, the football stadium and east stadium parking lot basins intermittently produce a greater volume of storm water runoff than existing retention Pond B43/44 can store. As a result, this pond sometimes overflows and flooding occurs in the vicinity of the pond. Storm water management facilities in Basins 43 and 44, the stadium and stadium parking area and the indoor practice facility area, should be re-designed and modified as required to eliminate flooding in this area during major storms. Significantly increasing the capacity of existing Pond B43/44 is not feasible given the density of development in the vicinity of the pond. Two potential remedies for this problem would to:

  - Re-grade the Basin B43 stadium parking lot to discharge eastward into a new enlarged 22nd St. storm sewer and direct some or all of Indoor Practice Facility Basin 44 runoff into the new 22nd St. storm sewer; the new 22nd St. storm sewer would run along the west side of the street and would merge with the existing 36” diameter storm sewer that begins at the intersection of 22nd St. and Grand Avenue.

The cost estimate shown below is based on assumed re-grading and re-surfacing of the stadium parking lot in Basin B43 to drain eastward, installing catch basins, and installing approximately 1,000 linear ft of new 24" storm sewer under the west edge of 22nd St.; and

- o Convey runoff from the Indoor Practice Facility Basin B44 and the stadium parking Basin B43 to a new detention pond located in an existing landscaped area at the intersection of 20th St. and Grand Avenue.

  The cost estimate for this option is based on constructing an incised detention pond having a capacity equal to 60% of the 100 year, 6 hour storm water runoff volume over the basins in question.

- Re-designing storm water management facilities for the basins that discharge into the Ivinson Avenue storm sewer system in order to improve storm water conveyance and reduce flooding in this area:

  Storm water drainage problems in the Ivinson Avenue area are significant and not easily corrected given the density of development in this area and the location of the area close to the core of the campus. Construction costs in this area are probably high and the inconvenience to UW students, faculty, and staff during construction would likely be significant. Potential options for alleviating storm water management problems in this area include directing storm water from some contributing basins to other storm water management facilities, installing larger storm sewer pipes and additional catch basins along Ivinson Avenue, and installing new storm sewer lines along an alignment that is not within the Ivinson Avenue traveled way, such as under the north sidewalk. None of these alternatives would be simple or inexpensive.

  Installing a new or larger storm sewer line in Ivinson Avenue is not practical since downstream City storm sewers are 24" in diameter, and no larger diameter City storm sewers are located in the vicinity of the intersection of 9th St. and Ivinson St. to receive additional piped Ivinson St. discharge. Existing City storm sewer pipes that are located south of Ivinson Avenue are typically 12" and 15" in diameter. No City storm sewer pipe is located under Grand Avenue between 5th St. and 15th St. Existing landscaped depressions in Basins B6, the southwest campus basin, and B7, the Merica Hall basin, near the intersection of Ivinson Avenue and 9th St., may be usable as storm water detention ponds. Any such use for these areas would require careful planning in order to avoid detracting from the appearance of this core part of campus.

The cost estimate shown below is based on assumed construction of a new 18" storm sewer line with catch basins under Ivinson Avenue east of the existing campus depressions, discharging new 18" pipe storm water discharge into one or both of the existing depressions, and installing smaller diameter outlet pipes from the depressions to the existing 24" western Ivinson Avenue storm sewer at a point near the intersection of Ivinson Avenue and 9th St.. The purpose of this approach would be to capture a portion of storm water runoff that reaches Ivinson Avenue, thereby reducing flows in existing Ivinson Avenue storm sewers, to direct that runoff to the landscaped detention depressions, and to discharge this runoff at a lower peak discharge rate from the detention depressions into the existing 24" storm sewer that is located under Ivinson Avenue at the intersection of Ivinson Avenue and 9th St..

- Re-designing, modifying, or replacing the existing detention Pond B21, which is located at the southeast corner of the intersection of 15th St. and Harney St.

  Since Pond B21 is located in an undeveloped area and receives storm water runoff from largely undeveloped areas, re-design and modification of this detention pond should be completed based on long-term development plans within the contributing drainage basin. If and when modified, this structure should be designed to receive both current and anticipated future, post-development storm water runoff. Landscaping within and around the pond should also be included so that the structure serves both the practical purpose of attenuating peak post-development storm water runoff and also provides a visually appealing site.

  The cost estimate shown below is includes engineering, surveying, and construction and is based on assumed doubling of current pond capacity and completing post-construction landscaping.

3. Options Summary

A summary of proposed options pertaining to improvements to the campus storm water management system are summarized in Table IV-I-1 below. A work calculation spreadsheet showing derivation of these estimates is included in Appendix IV-GHIJ-1. Each cost estimate was prepared based on 2009 dollars and typically included engineering and related professional service costs as well as a 25% contingency.

Table IV-I-1 - Table IV-I-1 – Summary – estimated engineering and construction costs – storm water management system engineering and construction

Item no.	Description	Estimated total cost
1	15th St. catch basin assessment, design, and construction	$ 66, 000
2	Engineering analysis and design – Law Bldg/A&S/Physical Sci basins	$ 36,500
3	Design and construction – stadium parking lot and 22nd Street storm sewer	$ 780,000
4	22nd St. / Grand Ave. detention pond	$182,000
5	Ivinson Avenue storm sewer and campus detention ponds	$ 275,000
6	Pond B21 enlargement and landscaping	$ 83,500

J. Sanitary Sewer

1. General Overview

The UW campus sanitary sewer collection system is a gravity-flow system that discharges at various points along the campus periphery into the surrounding City of Laramie sanitary sewer collection system. Campus sanitary sewer collection system data that was collected and organized during this project should provide a valuable tool to UW staff and to those involved in modeling, designing, and constructing future campus facilities.

2. Options Evaluation

Options available to UW regarding sanitary sewer facilities that were developed during this study included:

- Preparation of a campus sanitary sewer system model by UW staff is apparently under way. An option that would allow UW to calibrate and refine the in-progress sanitary sewer model so that the model would be more useful would be metering current campus sanitary sewerage flows over time at various points around campus.

  This work should both provide a better basis for calibrating and using the campus sanitary sewer model and allow UW staff to assess collection system performance at this time and during future development more accurately.

  In addition, a campus sanitary sewer collection system infiltration/inflow (I/I) study should be completed using collected sanitary sewer flow data in conjunction with concurrent precipitation data. The goal of the I/I study would be to determine the approximate extent of seepage of groundwater and/or infiltrating precipitation into the campus sanitary sewer collection system. Minimizing infiltration and inflow is considered good standard procedure for maintenance of a sanitary sewer collection system.

Flow monitoring in manholes can be completed at one, two, or more manholes at any one time. Manhole flow monitors are typically moved to different manholes after adequate data has been collected from the manhole in which monitoring equipment was originally installed. Purchase and use of more units of monitoring equipment would increase the cost of monitoring but reduce the duration of monitoring efforts. Data from flow monitoring devices should be recorded daily during time periods when UW classes are in session. The duration of monitoring at any manhole should be adequate to provide reasonably consistent data for week day and weekend flows. Precipitation data, presumably from a simple rain gauge located on the roof of a campus building should be collected concurrently with sewer flow data. The precipitation data would be used as a basis of the proposed infiltration and inflow (I/I) study that is described above.

Campus manholes at which flow monitoring could take place include the following ten manholes where UW sanitary sewer pipes discharge into the City of Laramie collection system:

- Manhole at point 3078 on the north side of Lewis St. between 9th St. and 10th St.;
- Manhole at point 3072 on the south side of Lewis St. between 10th St. and 11th St.;
- Manhole at point 3051 on the south side of Lewis St. between 11th St. and 12th St.;
- Manhole at point 3028 on the east side of 9th St. at the intersection of 9th St. and Lewis St.;
- Manhole at point 2014 on the east side of 9th St. at the intersection of 9th St. and Fremont St.;

- Manhole at point 2012 on the east side of 9th St. at the intersection of 9th St. and UW Avenue;

- Manholes at points 5032, 2002, 2004, and 2149 in Ivinson Avenue at or near the intersection of Ivinson Avenue and 9th St.;

- Manhole at point 3350 located south of Ivinson Avenue and Knight Hall;

- Manhole at point 3219 at the intersection of 15th St. and Grand Avenue; and

- Manhole at point 3254 along the north side of Grand Avenue near Downey Hall.

- Installing new manholes at appropriate locations on campus.

  Installing manholes at points on the existing campus sanitary sewer system where sanitary sewer line crosses or other connections currently exist would significantly enhance the ability to maintain the campus sanitary sewer system and would decrease the likelihood of sewer line clogging at these locations.

- Installing larger diameter gravity sanitary sewer lines with manholes, including 12" diameter, 18" diameter, and 24" diameter lines.

  As noted in report Section 2.H., some existing gravity sanitary sewer lines on campus are apparently incapable of conveying current wastewater discharges or discharge into smaller diameter sewer lines. Construction cost estimates were therefore prepared for a range of relatively large diameter replacement sanitary sewer lines and manholes. Determination of specific new sanitary sewer line sizes should be completed during the design process. Use of the campus sanitary sewer system model that is currently under preparation by UW staff should be beneficial during design of future sanitary sewer lines.

3. Options Summary

Options for improving the existing campus sanitary sewer collection system include installing new manholes at points where existing sanitary sewer lines cross or intersect but at which no access to the cross or intersection is currently available and replacing and enlarging existing campus sanitary sewer lines where clogging currently occurs or where current pipe diameters are inadequate.

Table IV-J-1 below contains a summary of recommended sanitary sewer modifications. Each estimated cost is in 2009 dollars and includes an estimated engineering cost and a 25%. Estimated costs for installing 12", 18", and 24" diameter gravity sanitary sewer are for units of 200 linear feet of gravity sewer line, including trenching, installing PVC sewer pipe, and installing one manhole. Typical manhole spacing is 400 feet, but, given the congested nature of the UW Campus, these estimates assume a more conservative 200 foot manhole spacing. A work calculation spreadsheet showing derivation of these estimates is included in Appendix IV-GHIJ-1.

Table IV-J-1. Summary – estimated engineering and construction costs – sanitary sewer system engineering and construction

Item no.	Description	Estimated cost
1	Flow metering in manholes, collecting precipitation data	$ 27,500
2	Infiltration and inflow (I/I) study and recommendations	$ 22,500
3	Installing new manholes (per manhole)	$ 15,500
4	New gravity sanitary sewer line – 12" dia – per 200 lf w/1 manhole	$ 67,000
5	New gravity sanitary sewer line – 18" dia – per 200 lf w/1 manhole	$ 70,000
6	New gravity sanitary sewer line – 24 " dia – per 200 lf w/1 manhole	$ 78,000

Assessment of existing campus sanitary sewer and storm sewer systems for this report has indicated that significant issues pertaining to these two utilities exist along a single corridor through campus. This east-west corridor runs approximately between 22nd St. on the east and 9th St. on the west and generally follows Ivinson Avenue, King Row, and a line between the east end of King Row and 22nd St.. Given the significance of both sanitary and storm sewer issues within this corridor, UW may wish to consider a major corridor utility design and construction project to address sanitary sewer and storm sewer issues as well as, if appropriate, other utility issues. A comprehensive approach to utility replacement should reduce overall costs and disruption to campus activities when compared to an incremental approach to improving utilities within this corridor. Expansion of sanitary and storm sewer conveyance capacities within this corridor would have to be coordinated closely with the City of Laramie since existing City-owned gravity sanitary and storm sewer lines west of the UW Campus corridor are of generally small diameter and may not safely convey increased discharges from larger campus gravity sanitary and storm sewer lines.

K. Additional Civil Utility Considerations

1. Utility Corridors

Utility corridors are typically one of two types – street and road rights-of-way and recorded utility easements within which buildings may not be constructed. Street and road rights-of-way are typically controlled by municipalities and states, though some campus streets may be owned by the UW. Above-ground and underground utilities that may be placed in utility corridors may include public utilities; such as water lines, sanitary sewer lines, or storm sewer lines; franchised utilities; such as telephone lines, electric lines, natural gas lines, or other communication lines; or UW-owned utilities; such as steam lines, chilled water lines, and other UW utilities. The City of Laramie typically requires placement of City-owned and maintained public utilities beneath street pavement or beneath parking lot pavement. The reason for this approach is apparently City desire to ensure, to the extent possible, that future building construction will not take place over existing public utility lines.

Water lines, sanitary sewer lines, and/or storm sewer lines and appurtenances that are associated with or required by new development are typically designed by the development owner, permitted for construction by the Wyoming Department of Environmental Quality with concurrence by the City of Laramie, constructed by the development owner, and eventually owned and operated by the City. As a result, public utility design and construction within the City must conform to City requirements. New public utilities that will be constructed during future campus development will therefore presumably be required to be placed beneath existing or future street pavement. Franchised utilities will presumably be placed in easements that will extend through and across UW property so that future structures can be provided with franchised utility services. These easements typically run adjacent to street rights-of-way or along parcel boundaries.

Areas in which future UW development will presumably occur have been defined and described as part of this project. These areas are described in Table II-H-1 in Appendix III-H-1. Most assumed future campus development will take place in areas that are currently developed as residential areas or in which existing structures, some owned by the UW, are located. The delineation of utility corridors to serve future campus development is complicated by the assumed existence of utilities and utility easements in much of the future development area and by presumed development by the UW of relatively large tracts, such as that between 15th St. and 9th St. and between Lewis St. and Flint St., over an extended period of time.

Recommendations regarding utility corridors include:

- Assume that future public utility construction will take place under existing or future streets and that streets will therefore comprise a significant portion of campus utility corridors;

- Preliminarily define future utility corridors to include:

  - Bradley St. right-of-way between 9th St. and 15th St.;
  - 15th St. right-of-way between Harney St. and Grand Avenue;
  - 22nd St. right-of-way between Harney St. and Grand Avenue;
  - A defined 30 ft wide utility easement running westward across UW property from the existing CEP to 15th St. and additional defined easements from the plant running eastward along but outside the right-of-way of Harney St.;
  - Thirty ft wide utility easements for franchised and UW utilities located along and inside the perimeter of each parcel in which future development is planned, such as the parcel that is located between Ivinson Avenue and Grand Avenue and between 9th St. and 15th St.; and

- Complete a street assessment that will result in mapping, using products of this project as a base, existing public, franchised, and UW utilities that are located under existing streets that are appurtenant to areas of future campus development and determine the feasibility of modifying or expanding utilities under each street as part of an overall street reconstruction project.

2. Storm Water Regulations

Regulation of storm water quality is administered by the U.S. Environmental Protection Agency and, in Wyoming except for on the Wind River Indian Reservation, by the Wyoming Department of Environmental Quality, Water Quality Division (WDEQ/WQD). Wyoming is located in USEPA Region 8, offices for which are located in Denver, Colorado. The national USEPA internet site and the Region 8 USEPA internet site contain extensive quantities of information pertaining to storm water quality regulations.

Storm water quality regulations fall under the National Pollutant Discharge Elimination System (NPDES), which in Wyoming is referred to as the Wyoming Pollutant Discharge Elimination System (WYPDES). As the name of the storm water quality regulatory system implies, the focus of storm water regulation is on potential impacts of storm water runoff on the quality of waters of the United States. NPDES/WYPDES permits are required for several activities and entities, including during-construction storm water pollution prevention plans (SWPPP), storm water pollution prevention plans for industrial facilities such as coal mines, and municipal storm water storm water management plans.

During-construction SWPPPs will be required for future campus construction that disturbs an aggregate area of more than one acre. USEPA and WDEQ/WQD provide guidelines for preparing during-construction SWPPPs. In Wyoming, WDEQ requires preparation and implementation of during-construction SWPPPs for all construction activities that disturb an aggregate area of more than one acre, but submittal to and review by WDEQ/WQD of during-construction SWPPPs is required only if the disturbed construction area covers 100 acres or more. If more than five acres but less than 100 acres are to be disturbed, WDEQ/WQD requires filing of a Notice of Intent to prepare and implement a during-construction SWPPP. Typically, copies of during-construction SWPPPs for projects covering less than 100 acres are submitted to the City of Laramie Engineer as a courtesy prior to the start of the project for which an SWPPP was prepared. The during-construction SWPPP document, including monitoring and repair records, must be maintained at each project site during construction and by the project owner for a period of three years after completion of construction.

Since the UW is located within the corporate boundary of the City of Laramie and since the population of the UW exceeds 10,000, municipal storm water regulations apply to the UW. While, in past years, urban sanitary sewer collection systems and storm water collection systems were sometimes combined, current regulations require separation of sanitary sewer collection, conveyance and treatment systems from storm water collection, conveyance, and treatment systems. Municipal separate storm sewer systems are referred to as MS4s in regulatory literature. AN MS4 may be located in an incorporated municipality, a local sanitary sewer district, a large hospital complex, a military base, a prison, or a UW. MS4 systems have historically discharged untreated storm water into local rivers and streams.

Medium MS4s are typically located in municipalities having populations between 100,000 and 249,000. Large MS4s are located in municipalities having populations of 250,000 or more. Large and medium MS4s are regulated under Phase 1 USEPA regulations. Approximately 900 medium and large MS4s have been identified and are regulated in the United States. Small MS4s may or may not be regulated under Phase II USEPA regulations. Regulation of small MS4s is typically based on determination by the permitting authority that an MS4 is located in an urbanized area, that an MS4 that is located outside an urbanized area may adversely impact water quality, or that a small MS4 is physically interconnected to a regulated MS4. An urbanized area is defined at length by the USEPA, with the primary criterion being Bureau of Census population data. Key components of the complex USEPA definition for an urban area include populations of at least 50,000 and an overall population density of at least 1,000 people per sq mile. Designated and regulated MS4s in Wyoming include the City of Casper and the City of Cheyenne. “Non-standard” regulated MS4s in Wyoming include Casper College and the Veteran’s Administration Medical Center in Cheyenne.

Current USEPA guidelines require state regulatory agencies to assess all municipalities having populations between 10,000 and 50,000 and to determine the need for storm water quality regulatory permitting. Wyoming Department of Environmental Quality, Water Quality Division (WDEQ/WQD) personnel are currently visiting and reviewing municipalities around the state, but are moving slowly during completion of this process. Laramie and the UW will eventually be assessed by WDEQ/WQD. The WDEQ/WQD review will focus on current and historical negative impacts of municipal and UW storm water runoff on area surface water quality. This assessment will be general in nature and will not include water quality sampling or assessing specific water quality parameters.

If Laramie and the UW are deemed by WDEQ/WQD to require permitting as regulated MS4s under the WYPDES storm water program, the two entities will be encouraged to work together to prepare and submit a WYPDES general permit application and to complete the six minimum measures that are required by USEPA for MS4 regulation, including:

- Developing an educational program for all stakeholders;
- Ensuring public involvement by means of public meetings and mailed information brochures regarding storm water discharge and the desire to improve storm water runoff water quality;
- Eliminating cross connections between sanitary and storm sewer conveyance pipes and other illicit storm water discharges;
- Enforcing during-construction storm water pollution prevention plan (SWPPP) regulations for construction that disturbs more than one acre;
- Enforcing long-term SWPPP regulations for sites after completion of construction and/or re-development; and
- Reviewing municipal functions such as herbicide application, recycling, and other operations to seek to reduce negative impacts on storm water runoff water quality.

WDEQ/WQD currently encourages municipalities and institutions to begin now to plan for conformance to MS4 storm water quality regulations so that, when assessed by WDEQ/WQD in the future, these entities will have a program in place. In Casper, the City and college have collaborated to organize and operate a joint storm water management team. WDEQ/WQD recommends that the City of Laramie and the UW follow a similar approach.