



University of Colorado – Boulder Energy Planning Assessment Using REopt

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Summary

- PV and battery energy storage are recommended for reducing costs, contributing to climate goals, and enhancing resiliency
- Existing CHP plant, ground source heat pumps, solar water heating, biomass heating, landfill gas, and fuel cells are not found to be cost-effective
- For offsetting carbon at lowest costs, existing CHP plant should only be run during the winter without the steam turbine
- CU is likely to meet their 2020 carbon goal based on current trends with no or little additional investment required
  - Assumes continued aggressive load growth management by CU and Xcel grid carbon factor projections are accurate
- Meeting 2030 goal of 50% CO_2 reduction from 2005 baseline will be very costly
  - Can be met with PV and biomass heat plant, but will cost CU $169M more than business as usual
- Consider expanding carbon reduction opportunities beyond the physical boundary of the campus, particularly in light of the 2050 75% CO_2 reduction goal
  - Explore potential for renewable gas/biogas contracts for delivery via existing natural gas system
  - Explore off-site renewable project development (e.g. community solar)
  - Transportation electrification can reduce Scope 3 emissions. Although not included in the scope of this analysis, perhaps CO_2 reductions from other sources can be credited toward overall university emissions targets
  - Investigate future renewable energy and/or energy storage coordination with City of Boulder

Introduction

Scope of Work

- Assess the technical and economic potential of the following technologies:
  - Photovoltaics
  - Biomass
  - Landfill gas
  - Solar hot water
  - Fuel cells
  - Ground source heat pumps
  - Electric energy storage
  - Utility grid
  - Existing combined heat and power plant
- Technologies originally included in the SOW but excluded from consideration during project execution by CU
  - Off-site wind
  - Thermal energy storage
- Analysis to include identification of technologies that reduce life-cycle costs as well as lowest cost pathway to carbon goal

Results

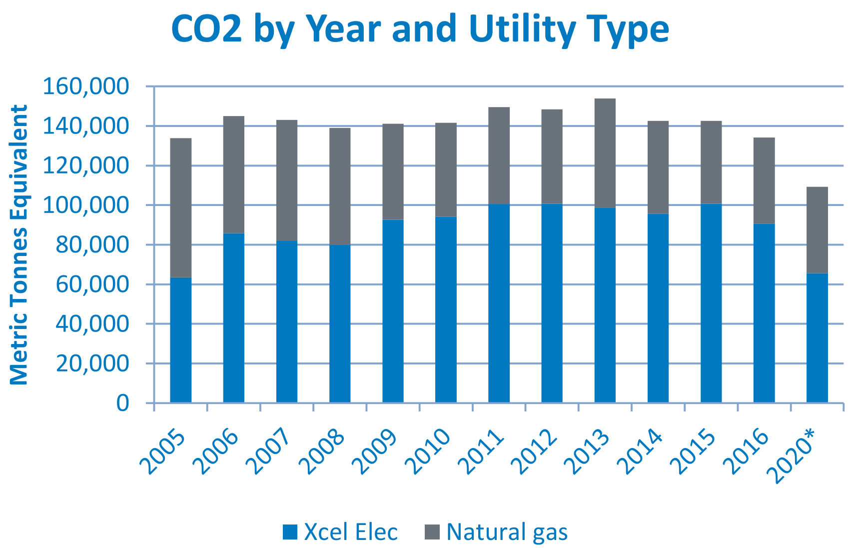
CO2 Emissions Goals

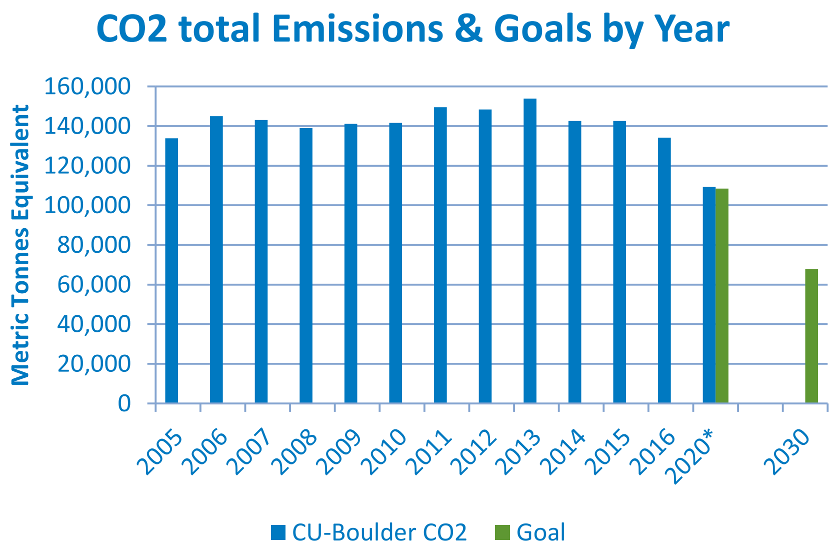
Goals	2005	2020	2030	2050
Reduction from 2005 baseline (%)		20%	50%	80%
Metric tons of CO2 equivalent	135,609 (baseline)	108,487	67,805	27,122

- Goals in table are for electricity and heating fuels
- 2016 actual: 134,377 metric tons CO2 equivalent for utility purchased electricity and natural gas
- CU's existing PV and management of load growth with campus expansions and Xcel Energy's move to more renewables and natural gas generation have held carbon footprint essentially flat since 2005

Baseline

- If current load levels stay flat, CU is projected to spend $303,000,000 over 25 years on electricity and natural gas in net present value terms
- If utility loads are held flat and Xcel's grid carbon factor projections are accurate, business-as-usual (BAU) campus CO2 emissions would be 109,400 mTe in 2020
  - Mix: 60% electricity / 40% natural gas
- CU is close to the 2020 goal of 108,487 mTe if the university continues to aggressively manage load growth and Xcel's grid carbon factor projections are accurate
  - The projected 2020 CO2 value assumes same consumption of natural gas and utility purchased electricity as 2016 and applies the projected 2021 emission factor for Xcel electricity (Xcel didn't provide an emission factor for 2020)





* 2020 electricity emissions based on Xcel 2021 projected emission factor

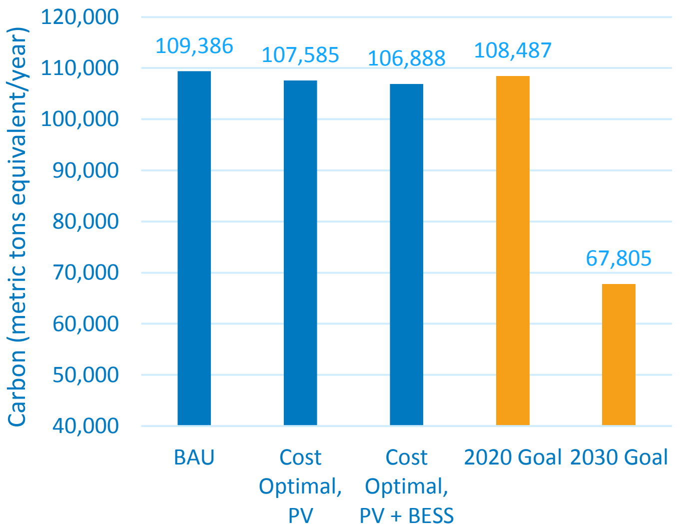
Summary of Cost-Effective Findings

- PV is cost effective and recommended for simultaneously reducing operational costs and contributing to climate goals
- Adding a large scale battery energy storage system (BESS) for managing peak demand charges from Xcel is cost effective. If Xcel were to require standby charges for BESS operation, the economic motivation for BESS is eliminated.
- Inclusion of BESS can also contribute to resiliency within a potential future microgrid if specified for that purpose
- Coupling of BESS with PV increases the scale of cost-effective PV
- Existing CHP plant, ground source heat pumps, solar water heating, biomass heating, landfill gas, and fuel cells are not found to be cost-effective
- Existing CHP plant is costly to operate due to low Xcel Energy electricity costs and Xcel's high standby tariff for CHP. To positively impact CO2 emissions at least cost, the CHP plant should be run only during the winter and operate without the steam turbine to maximize steam utilization and offset boiler natural gas consumption.

Cost Optimal Solution

- Economics in table assume CU purchases system. Sensitivity on PV costs and financing options are presented on later slides. *Economic bottom line is virtually unchanged whether CU self-finances or procures through a power purchase agreement.*
- At projected costs, an *additional* 3,000 kW-DC of PV is found to be optimal
- At this size, PV reduces total campus CO2 emissions by about 1.6% from BAU to 107,858 metric tons per year.
- If coupled with BESS, cost-optimal PV size increases to 4,200 kW-DC
- Both the cost optimal PV-only and PV + BESS solutions meet the 2020 goal

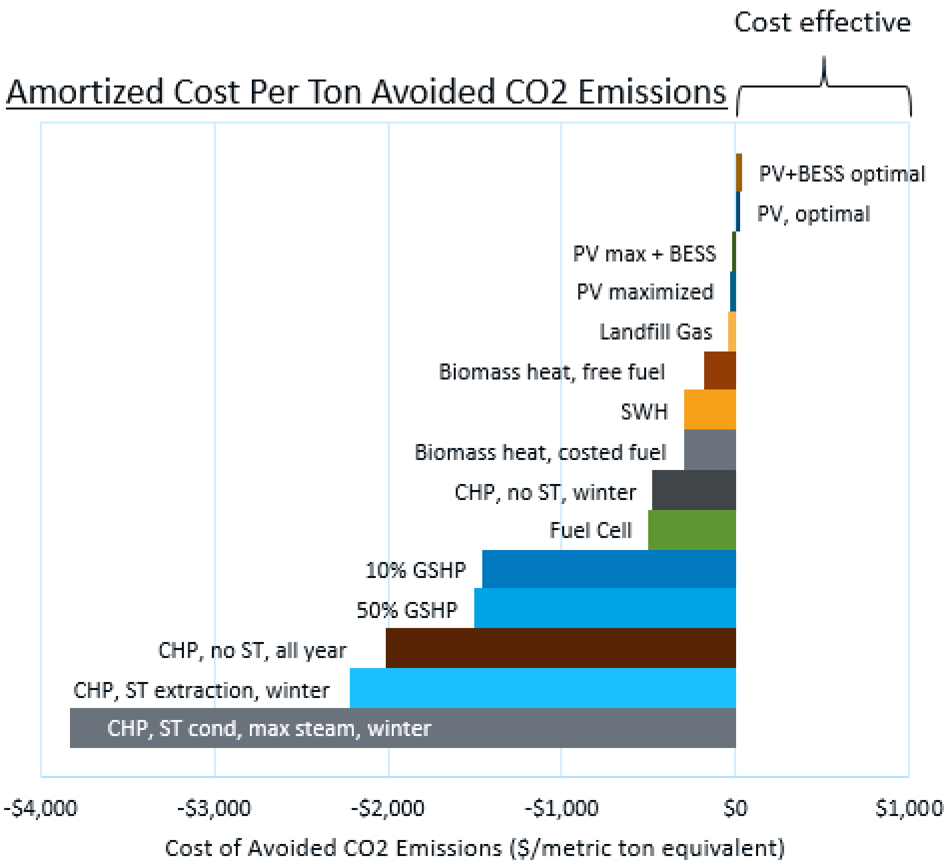
	PV	PV + BESS
Additional PV size (kW-DC)	3,022	4,200
BESS (kWh / kW)		3,082 / 1,267
Capital Costs	$4,532,710	$9,947,400
Net present value	$1,096,000	$2,160,000
Savings-to-Investment ratio*	1.24	1.22
Utility electricity (kWh/yr)	148,816,000	147,197,000
Utility electricity reduction (kWh/yr)	4,189,000	5,808,000
Utility electricity reduction (%)	2.7%	3.8%
Total campus CO2 (metric tons eq.)	107,858	106,888
CO2 reduction (metric tons eq.)	1,801	2,498
CO2 reduction (%)	1.6%	2.3%

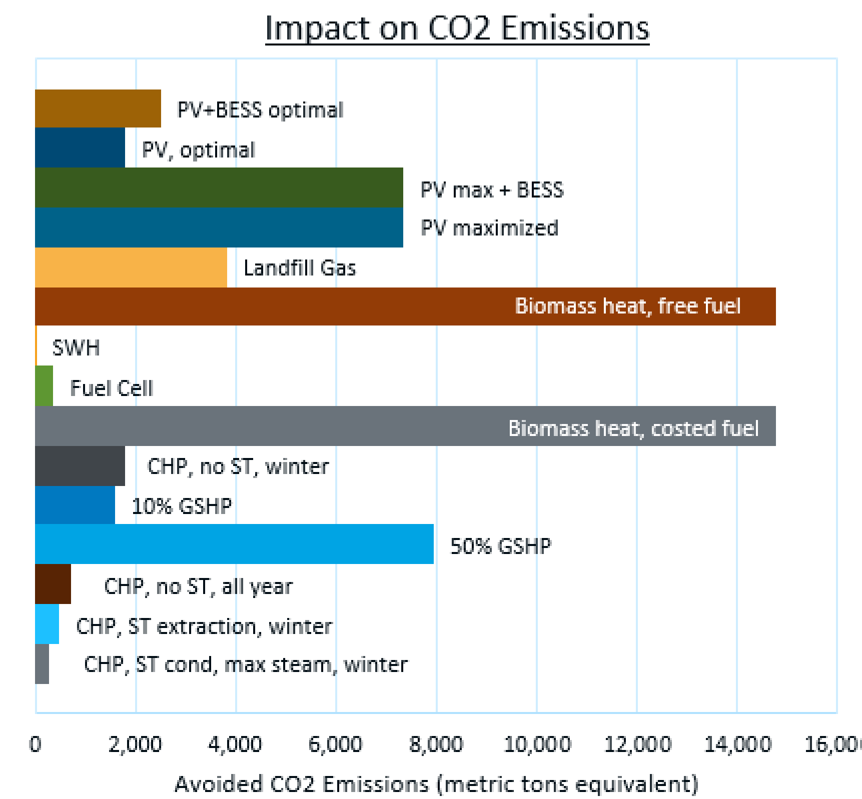


* Savings to investment ratio is the net present value of the savings divided by the initial investment. Values > 1 indicate positive economics.

Cost and Impact Carbon Reduction

- Carbon reduction cost by technology is shown in the figure on the left based on a $/metric ton where estimated net present values (NPV) are amortized ‘per year’
  - Negative values show projects that have negative NPV; these projects are not life-cycle cost effective but will reduce overall carbon footprint
  - Positive values show positive-NPV projects. These projects save costs over their lifecycle and reduce carbon. Only PV and PV + BESS when sized for maximum economic gain are found to be cost-effective.
- Carbon reduction in metric tons equivalent by technology is shown in the figure on the right for the sized analyzed





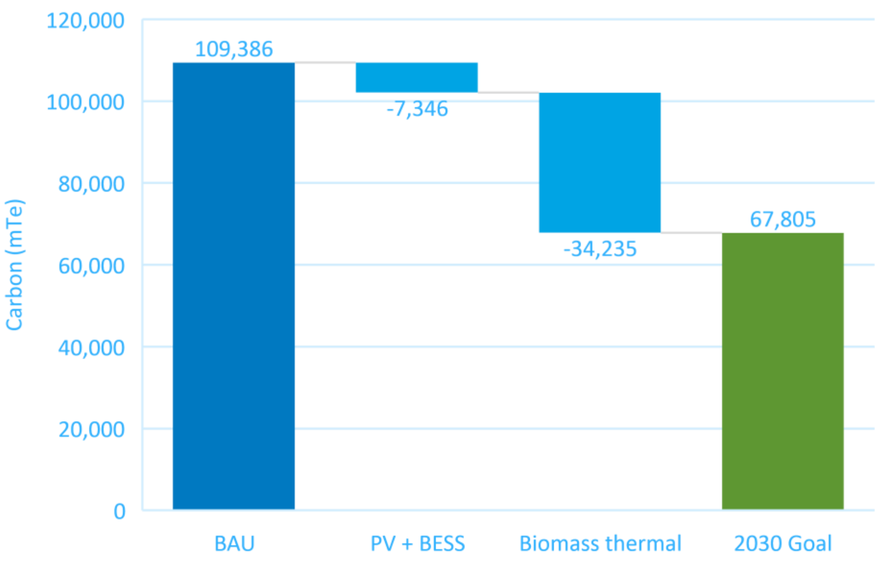
2030 CO_2 Reduction Goal

- 2030 goal is 67,805 mTe
- BAU carbon projection is 109,386 mTe
- To reach goal, CU needs to reduce annual carbon by 42,479 mTe. This is equivalent to:
    - Replacing 65% of utility electricity with renewable electricity, or
    - Replacing 97% of natural gas with renewable fuel or heat

Least cost pathway to 2030 CO2 goal

- Maximize PV to fill available space. Add BESS to improve economics.
- Displace significant portion of natural gas heating with wood burning heating plant
- Goal is aggressive and costly if to be accomplished with the set of technologies considered in this analysis: $195/ton of avoided CO2 emissions, amortized
- Installing a pipeline from the Boulder Landfill to supplement natural gas in East Plant steam boilers with landfill methane gas would be less expensive, but still a negative NPV, by reducing overall size of biomass heating plant. However age of landfill and declining gas production preclude landfill gas as a long-term climate action solution

	2030 Carbon Goal
Additional PV size (kW-DC)	12,343
BESS (kWh / kW)	4,075 / 1,738
Biomass heating plant (MMBtu/hr)	103
Capital Costs	$169,062,258
Net present value*	$-168,992,000
Savings-to-Investment ratio	0.0
Utility electricity reduction (kWh/yr)	17,084,000
Utility electricity reduction (%)	11.2%
Natural gas reduction (MMBtu/yr)	645,350
Natural gas reduction (%)	78.5%
Total campus CO2 (metric tons eq.)	67,805
CO2 reduction (metric tons eq.)	41,581
CO2 reduction (%)	38.0%



*Biomass fuel costed at $50/ton woody feedstock

PV Results, additional details

- PV is cost effective at $2.30/Watt-DC total installed costs and below
- With this threshold, CU should expect competitive offers since recent market data and analysis by NREL and others suggest current prices are:
  - Rooftop systems prices of $1.56 to $1.85/Watt-DC
  - Ground mount, $1.24 to $1.50/Watt-DC, likely at the higher end for CU due to space constraints that limit system size to 3.2 MW total
  - Carport, $2.14/Watt-DC for 1MW system
- If procured via power purchase agreements (PPA), offers in the range of $0.10 to $0.12/kWh should be attainable
  - PPAs below $0.125/kWh levelized over 25 years are found to be life cycle cost effective for CU
  - Lowest cost projects are likely to be on the ground or on flat roofs

PV Results, max buildout

- Compare cost-optimal solution to maximum buildout on all available space identified by CU
- Results on this slide assume CU self-finances the systems
- Building out campus PV to maximum 12,300 kW-DC of PV would reduce CO2 by about 6.7% from BAU but comes at a cost premium of about $4.6MM over 25 years

	Cost Optimal Sizing	Maximize PV installation
Additional PV size (kW-DC)	3,022	12,343
Capital Costs	$4,532,710	$20,616,000
Net present value	$1,096,000	-$4,556,000
Savings-to-Investment ratio	1.24	0.78
Utility electricity (kWh/yr)	148,816,000	135,894,000
Utility electricity reduction (kWh/yr)	4,189,000	17,111,000
Utility electricity reduction (%)	2.7%	11.2%
Total campus CO2 (metric tons eq.)	107,858	102,028
CO2 reduction (metric tons eq.)	1,801	7,358
CO2 reduction (%)	1.6%	6.7%

PV Results, sensitivity on PV costs and financing method

- For third-party financing, developer finances the project, captures federal tax incentives, and sells CU electricity produced from the systems
- Developer's profit is largely covered by the tax incentives so optimal sizes are the same and NPVs are similar between CU-financed vs. 3rd party financing

	CU Buys, $1.50/W	CU Buys, $2.00/W	CU Buys, $2.25/W	PPA, $1.50/W	PPA, $2.00/W	PPA, $2.25/W
Additional PV size (kW-DC)	3,022	991	472	3,022	991	472
Capital Costs for CU	$4,532,710	$1,982,430	$1,062,910	$0	$0	$0
Net present value	$1,096,000	$198,000	$19,000	$1,060,000	$174,000	$5,000
Savings-to-Investment ratio	1.24	1.10	1.02	n/a	n/a	n/a
LCOE ($/kWh)	$.088	$.112	$.123	$.089	$.113	$.124
Electricity production (kWh/yr), levelized	4,189,000	1,374,000	654,000	4,189,000	1,374,000	654,000
Utility electricity reduction (%)	2.7%	0.9%	0.4%	2.7%	0.9%	0.4%
CO2 reduction (metric tons eq.)	1,801	591	282	1,801	591	282
CO2 reduction (%)	1.6%	0.5%	0.3%	1.6%	0.5%	0.3%

CHP Results

- Xcel electricity costs are very low but have relatively high demand charges. However Xcel's standby tariff eliminates the CHP plant demand savings potential, making CHP uneconomic.
- Impact on 2020 CO_2 emissions is mixed, depending on operation mode
- For reducing CO_2 emissions, maximize HRSG steam sent to the steam header by running in winter and not using the steam turbine, highlighted in the table below
- Additional details of CHP modeling and results are included in the 'Technology Performance and Cost Assumptions' section

CHP Operation Mode	Net Present Value	CO2 Reduction (tons/year)	CO2 Reduction (%)
No Steam Turbine, summer operation	-$12,743,000	-1,063	-1.0%
No Steam Turbine, winter operation	-$17,609,000	1775	1.6%
With ST, extraction mode, summer	-$12,780,000	-927	-0.8%
With ST, extraction mode, winter	-$21,027,000	454	0.4%
With ST, condensing mode, maximizing steam to load, summer	-$16,318,000	-2,442	-2.2%
With ST, condensing mode, maximizing steam to load, winter	-$21,156,000	265	0.2%
With ST, condensing mode, maximizing power production, summer	-$20,162,000	-4,090	-3.7%
With ST, condensing mode, maximizing power production, winter	-$36,860,000	-6,709	-6.1%

GSHP Results

- Ran model for two cases. GSHP sized to meet:
  - 10% of campus heating and cooling loads
  - 50% of campus heating and cooling loads
- Due to efficiency gains, carbon is reduced however economics are poor

	10% Load Case	50% Load Case
Heat pump capacity (tons)	3,377	16,885
No. of ground loop wells (count)	4,516	23,584
Capital Cost	$49,801,350	$252,570,820
Net present value	-$48,058,450	-$248,775,520
Savings-to-Investment Ratio	0.03	0.02
Utility electricity (kWh/yr)	159,453,000	185,215,000
Utility electricity reduction (kWh/yr)	-6,448,000	-32,210,000
Utility electricity reduction (%)	-4.2%	-21.1%
Natural gas consumption (MMBtu/yr)	739,599	410,887
Natural gas reduction (MMBtu/yr)	82,175	410,887
Natural gas reduction (%)	10.0%	50.0%
Total campus CO2 (metric tons eq.)	107,799	101,439
CO2 reduction (metric tons eq.)	1,587	7,947
CO2 reduction (%)	1.5%	7.3%

Biomass Heat Plant Results

- Ran model for two fuel cost cases to bracket economics
- Biomass heat is not lifecycle cost effective, even with free fuel
- Biomass heat would have a strong impact on reducing carbon emissions.
- Plant requires up to 3 acres of land depending on fuel storage requirements
- Requires frequent truck deliveries, so would result in higher truck traffic on campus

	No Cost Fuel	$50/ton Fuel
Boiler capacity (MMBtu/hr)	34.1	34.1
Capital Cost	$26,142,000	
Net present value	-$55,072,000	$-92,428,000
Savings-to-Investment Ratio	-1.11	-2.54
Biomass fuel consumption (tons/yr)	35,900	
Natural gas consumption (MMBtu/yr)	543,392	
Natural gas reduction (MMBtu/yr)	278,382	
Natural gas reduction (%)	33.9%	
Total campus CO2 (metric tons eq.)	94,618	
CO2 reduction (metric tons eq.)	14,768	
CO2 reduction (%)	13.5%	

Solar Water Heating Results

- With low natural gas costs, SWH installations have stalled nationally
- Economics for CU for a 1,000 ft2 system are presented below
- SWH is not cost effective
- Installations would potentially compete for rooftop space with PV

	SWH
System Size (ft2)	1000
Capital Cost	$150,000
Net present value	-$128,000
Savings-to-Investment Ratio	0.15
Utility electricity (kWh/yr)	159,453,000
Natural gas consumption (MMBtu/yr)	821,378
Natural gas reduction (MMBtu/yr)	396
Natural gas reduction (%)	0.05%
Total campus CO2 (metric tons eq.)	109,365
CO2 reduction (metric tons eq.)	21
CO2 reduction (%)	.02%

Fuel Cell CHP Results

- Economics for a 460 kW phosphoric acid fuel cell fueled by natural gas are presented below
- High capital costs, maintenance costs, and low electricity utility pricing make economics very poor
- Standby tariff negates any demand savings

	Fuel Cell
System Size (kW)	460
Total installed cost ($)	$2,400,000
Net present value	-$3,868,000
Savings-to-Investment Ratio	-0.61
Utility electricity (kWh/yr)	149,589,000
Utility electricity reduction (kWh/yr)	3,416,000
Utility electricity reduction (%)	2.2%
Natural gas consumption (MMBtu/yr)	842,495
Natural gas reduction (MMBtu/yr)	-20,722
Natural gas reduction (%)	-2.5%
Total campus CO2 (metric tons eq.)	109,016
CO2 reduction (metric tons eq.)	370
CO2 reduction (%)	0.3%

Landfill Gas Results

- Boulder landfill is ~5 miles southeast and has potential methane gas production of 300 ft^3/min. Analysis considers economics of installing a pipeline to deliver landfill methane to East Utility Plant to supplement natural gas
- _15 year analysis period, a relatively short opportunity period due to declining gas production_ (landfill capped in 1995)
- Large uncertainty on cost, viability of gaining right-away approval for pipeline, and unknown interest of landfill owner
- Piping landfill gas to campus is not lifecycle cost effective but, on first examination, has relatively lower $/ton avoided CO2 costs than other technologies beside PV. However, methane production is a diminishing resource so for carbon displacement this opportunity does not represent a long-term solution.

	LFG pipeline
Boiler conversion capacity (MMBtu/hr)	6.8
Capital Cost for compressor station, pipeline, boiler conversion	$4,272,000
Net present value	-$2,073,000
Savings-to-Investment Ratio	0.52
LFG fuel consumption (MMBtu/yr)	90,177
Natural gas reduction (MMBtu/yr)	72,055
Natural gas reduction (%)	8.8%
Total campus CO2 (metric tons eq.)	105,563
CO2 reduction (metric tons eq.)	3,823
CO2 reduction (%)	3.5%

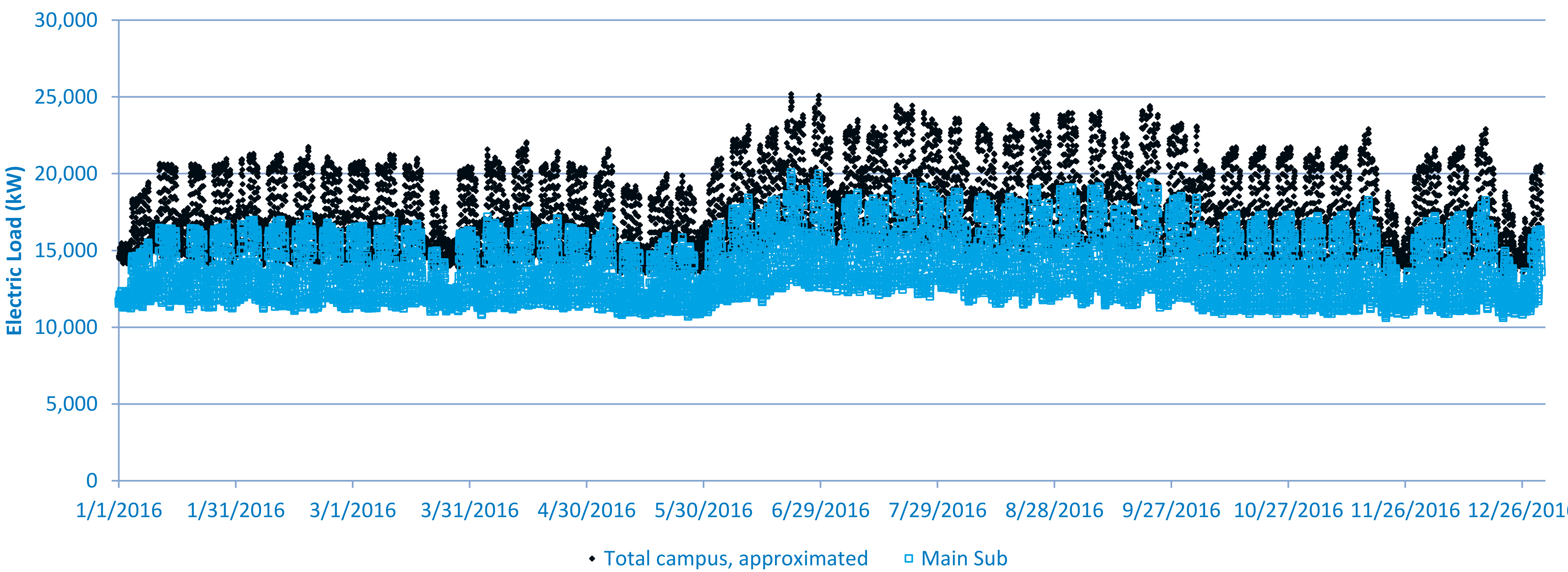
Key Inputs and Assumptions

Economic Parameters

- 25 year Analysis Period
- 4.0 % Nominal Discount Rate
- 2.5 % General Inflation Rate applied to O&M
- Utility cost escalation rates
  - DOE Energy Information Agency projections converted to constant escalation over 25 years
  - 2.25 % nominal electric utility cost escalation rate
  - 4.71 % nominal natural gas utility cost escalation rate
  - https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2017&region=1-8&cases=ref2017&start=2015&end=2050&f=A&linechart=ref2017-d120816a.12-3-AEO2017.1-8~ref2017-d120816a.13-3-AEO2017.1-8&ctype=linechart&sourcekey=0
- For third party financing of PV, developer ROI of 10% is assumed. Additionally, it is assumed the developer is able to monetize the 30% investment tax credit (ITC) and modified accelerated cost recovery schedule (MACRS) depreciation tax incentives and that these revenues are used to offer CU lower cost terms.

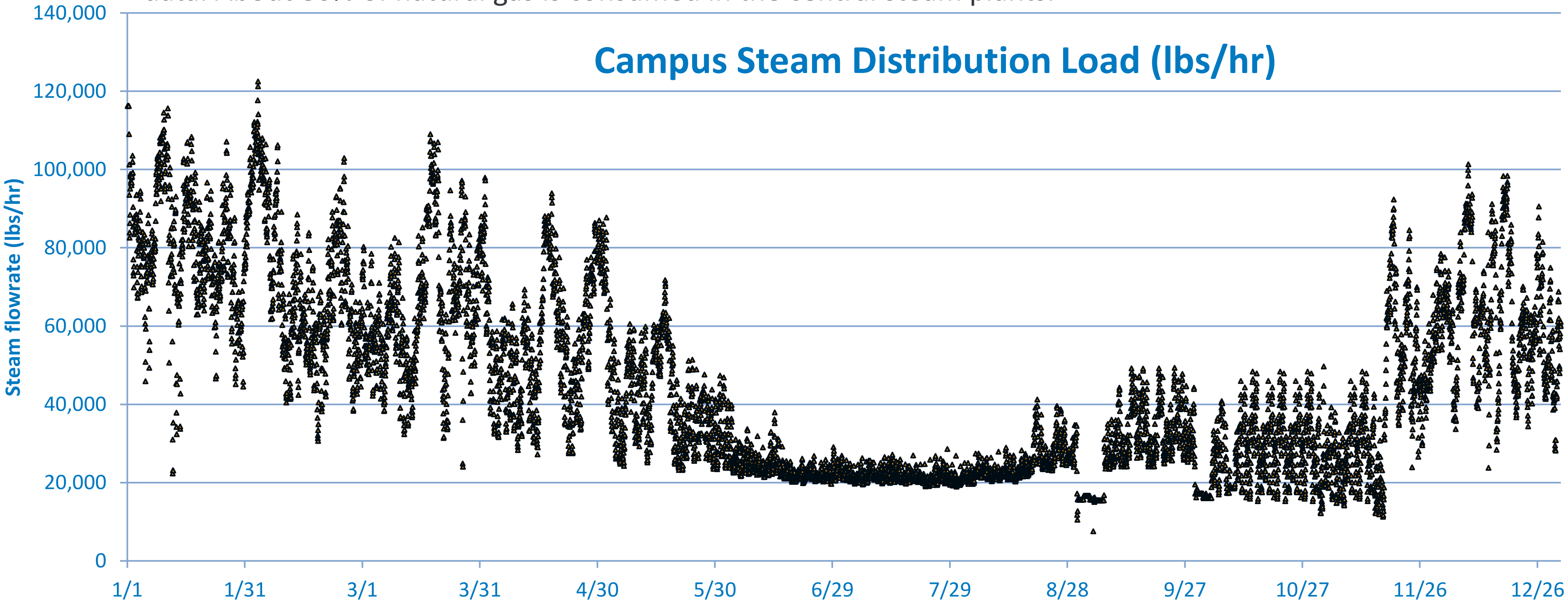
Electrical Load

- Using 2016 interval data from main substation
- Some minor ‘repairs’ required to correct two outage events and to removed two week operation of CHP plant in October
- Scaled main substation load to total annual purchased electricity for all other campus meters to approximate total campus electrical load profile
- Main sub (blue) and approximate total campus (black) loads shown below
- Peak 25,191 kW, 153 million kWh approximate total campus (all meters)



Thermal load

- Profile below developed from West Plant spreadsheet ‘WDEP Fuel and Steam Interval Data Calendar 2016.xlsx’, fuel usage interval data, steam totals from West Plant, and steam plant operation parameters below
- Estimated steam load by using:
    - 83% boiler efficiency
    - Enthalpy of steam of 1194 Btu/lbm at boiler outlet
    - Enthalpy of condensate of 128 Btu/lbm at boiler inlet
    - 90% condensate return
- Did not have interval data for East Plant steam generation. Interval data from West Plant scaled up to account for steam generation from East Plant using annual total steam production data provided for East plant.
- Additional heating loads at other buildings not connected to steam distribution are also accounted for in the model to account for total natural gas costs and associated emissions using actual gas consumption data. About 80% of natural gas is consumed in the central steam plants.



Electric Utility Costs

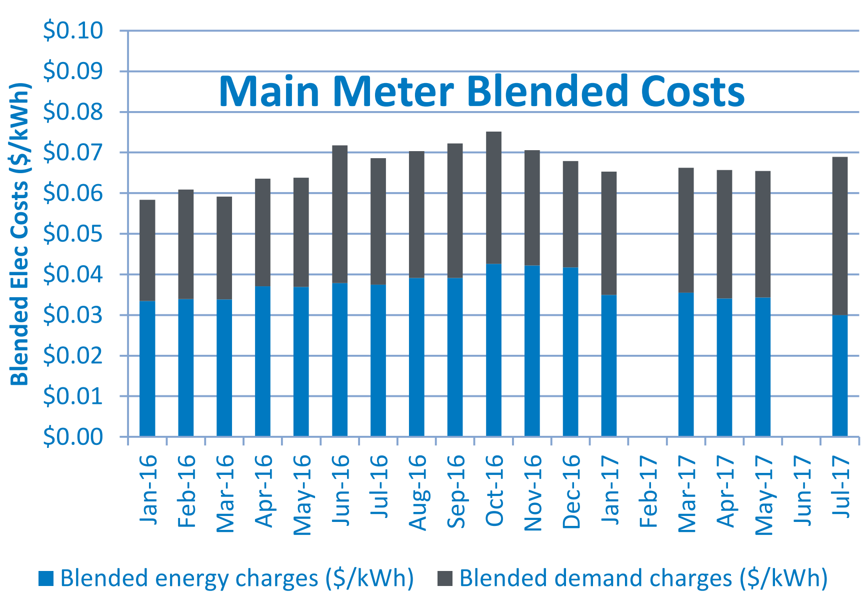
- Xcel rate tariff:
  - Primary General (PG)
  - Primary Standby (PST) when nominated to run CHP

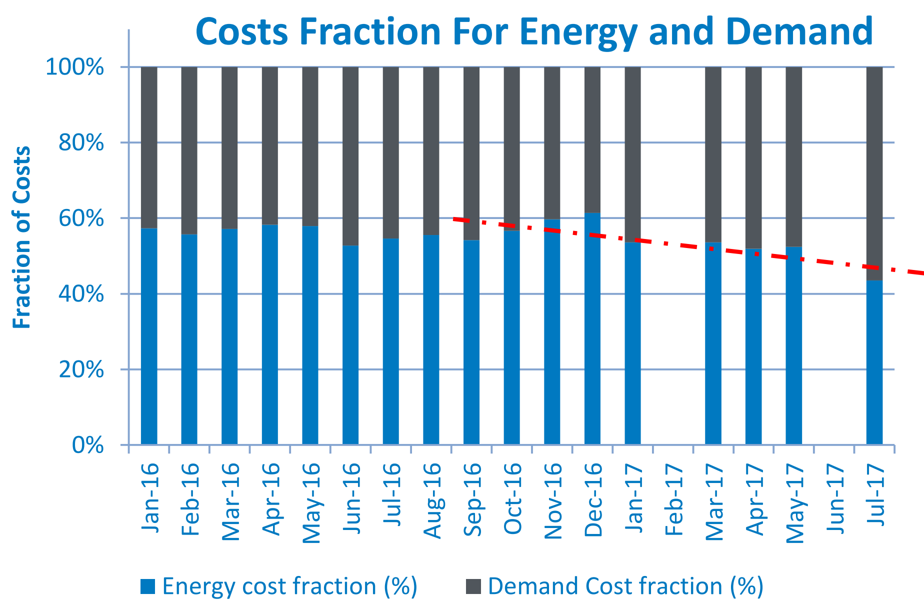
PG Base Rates	**Cost**
Service and Facility Charge	$322
Production meter charge	$192
Load meter charge	$192
Demand charge, distribution demand ($/kW)	$3.86
Demand charge, generation and transmission demand - summer season ($/kW)	$14.26
Demand charge, generation and transmission demand - winter season ($/kW)	$9.55
Energy ($/kWh)	$0.00458
PG Riders	
ECA (off-peak) ($/kWh). All hours EXCEPT 9a to 9p, Mo-Fr	$0.02505
ECA (on-peak) ($/kWh). Hours 9a to 9p, Mo-Fr	$0.03808
TCA Transmission Cost Adjustment ($/kW)	$0.32
DSM Demand Side Management Cost ($/kW)	$0.43
PCCA Purchased Capacity Cost Adjustment ($/kW)	$1.37
CACJA Clean Air-Clean Jobs Act Rider ($/kW)	$1.48
RESA Renewable Energy Std Adj	2%
GRSA (currently a small negative unit cost applied to some fraction of total energy)	

- Summer: June, July, August, September; Winter: all other months
- Distribution demand is 15-minute average peak for all hours in a month
- G&T demand determined Mo-Fr, 2p – 6p
- PST tariff requires CU to pay standby charges that are equivalent to avoided demand, thereby eliminating demand charge savings potential from CHP

Main Electric Meter Blended Costs

- Approximately 80% of total electricity consumption is through the main meter
- Blended total costs from 2016 through middle of 2017 range from $.058 - $.075/kWh
- Most recent bill shared for 7/2017 has blended cost of $0.069/kWh. Increased weighting of total costs attributed to demand charges in more recent bills
- For energy charges only, blended costs range from $.030 to $.043/kWh with lowest costs in this period in the last bill (7/17)



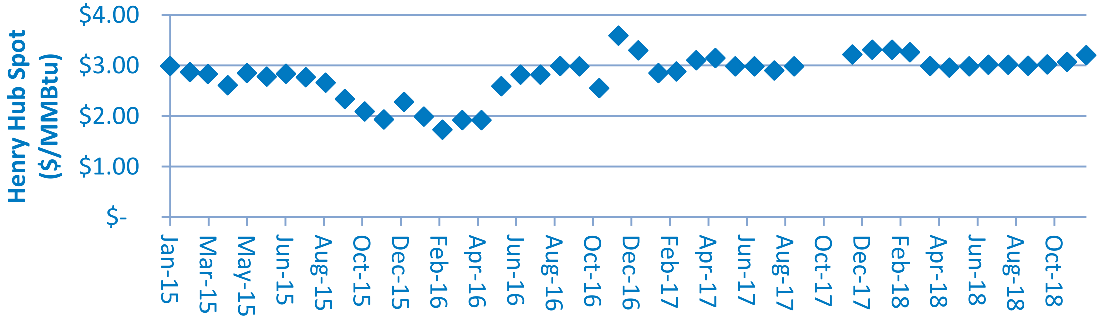


Natural Gas Costs

- Gas delivered by Xcel
- Delivery per T1 rate tariff, "Interruptible Gas Transportation Service“
- Gas bought wholesale

Usage charge ($/MMBtu)	$ 0.3072
Pipeline System Integrity Adjustment ($/MMBtu)	$ 0.2893
Interruptible specific facilities	$ 0.1568
General Rate Schedule Adjustment (GRSA) (%)	8.17%
Boulder Occupation Tax	3.74%
Total tariff ($/MMBtu)	$ 0.8148
Wholesale*, Year 0	$ 3.094
Total natural gas cost input for REopt model ($/MMBtu)	**$ 3.909**

*Wholesale taken as average of previous 12 months spot price for Henry Hub



CO2 Emissions Accounting

- Goals:
  - 20% reduction in greenhouse gases by 2020 from 2005 levels
  - 50% reduction by 2030
  - 80% reduction by 2050
- 2005 baseline: 135,609 metric tons CO2 equivalent for utility purchased electricity and natural gas (9,678,572 GSF)
- 2016 GHG: 133,377 metric tons CO2e, essentially equivalent to 2005 baseline (12,442,060 GSF)
- Current carbon emission factors
  - Electricity 0.599 metric tons/MWh
  - Natural Gas 11.7 lbs/therm = 0.05306 metric tons/MMBtu
  - Reference: Xcel Energy, "Energy and Carbon Emissions Reporting 2016 Summary", https://www.xcelenergy.com/staticfiles/xe-responsive/Environment/Carbon/Carbon-Reduction-2016-Energy-and-Carbon-Summary.pdf
- Xcel projects further reduction in electricity CO2 emission factor due to retiring coal plants and increasing mix of renewable energy and natural gas generators
  - Electricity 0.430 metric tons/MWh in 2021
  - Applying this to 2016 electricity & natural gas usage results in 109,200 metric tons CO2e, an 18% reduction for electricity and natural gas combined
- In analysis, using Xcel's 2021 electricity emission factor

Note: Projected 2021 emission factor for electricity is 51% of the value (49% lower) found in CU-Boulder spreadsheet 'carbon reduction goals spreadsheet' for 2005

Xcel Carbon Emission Factors* for Electricity

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2016	2021
MTCO2/MWh	0.839	0.833	0.794	0.746	0.734	0.761	0.732	0.700	0.688	0.688	0.599	0.43
Reduction from 2005		99%	95%	89%	88%	91%	87%	84%	82%	82%	71%	51%

* Values from 2005 – 2014 from CU spreadsheet, 2016 from Xcel website, 2021 from email cited above

Technology Performance and Cost Assumptions

Solar PV Analysis Inputs and Assumptions

- CU has 2247 kW of existing PV
- Available space for additional PV:
  - Rooftops: 4920 kW-DC
  - Open ground: 3220 kW-DC
  - Carports: 4200 kW-DC
  - Potential capacities per spreadsheet: “2017-5-1 Multi Site Solar Opportunity.xlsx” provided by E. Edwards email, 7/12/17
- Total Installed Cost:
  - Rooftops and ground mount: $1,500/kW-DC
  - Carport: $2,000/kW-DC
  - Costs based on information provided in, "U.S. PV System Pricing H2 2017: Forecasts and Breakdowns," GTM Research, December 2017 and analyst’s interpretation for CU application
- Operations and maintenance $20/kW-year, includes inverter replacement in Year 10
- Assuming fixed 20 degree tilt, facing south
- Use NREL PVWatts performance model
- Typical meteorological year (TMY) weather file to predict electricity generated by hour of the year
- 25 year useful life
- Year 1 electricity generation estimate 1383 kWh/kW-DC for a 15.8% capacity factor

Combined Heat and Power (CHP) plant

- Existing system resides at West Energy Plant
  - Two 10,000 kW combustion turbines (CT)
  - Heat recovery steam generator (HRSG) boiler
  - 3,410 kW steam turbine (ST), recently added
- When nominated with Xcel to run:
  - PST tariff applies
    - Application of PST tariff essentially means the CHP plant cannot reduce demand charges since they are replaced with standby charges
  - CU will run 24/7, all summer and/or all winter
  - Summer: June, July, August, September; Winter is all other months
  - Analysis assumes no supplementary firing of HRSG unit
- Steam turbine recently added to system
  - Power output range capable of approximately 96 kW to 3,410 kW for steam flow at inlet 6,500 to 50,000 lb/hr
  - Flexible design allows two possible operational modes: Condensing or Extraction
    - Condensing mode: All steam diverted through ST is condensed, maximizing power generation
    - Extraction mode: Some steam is extracted at a useful pressure for distribution to the campus steam loads, allowing simultaneous generation of power from ST and useful heat
    - Both these modes are explored in this analysis for both summer and winter operation
- Capital costs are sunk so not included in life cycle costs analysis
- O&M costs (Ref: notes from kickoff meeting)
  - 30,000 hr. overhaul costs $1.5MM
  - 60,000 hr. overhaul costs $3.25MM
  - 100,000 hr. overhaul costs $5MM
  - ($1.5MM + $3.25MM + $5MM)/100,000 hrs
  - = $97.5/hr. of runtime

CHP plant, cont.

- CU general operation scheme:
  - Run one CT at constant power output, likely 10,000 kW
  - Divert CT exhaust through HRSG to generate maximum amount of steam. CU unlikely to use supplementary firing capability on HRSG
  - A minimum amount of HRSG steam is supplied to CT intake for NOx emission control
  - Remaining HRSG steam can be:
    - Sent to campus steam distribution header
    - Sent to ST for generation additional power and some of this steam can be extracted at low pressure and sent to steam header
    - Any excess steam is supplied to the CT intake for 'augmentation' which improves the operation efficiency of the CT
- CHP performance model provided by CU
  - Model "GEPerformance0701a 20050429.xls" from CU. Did not include new steam turbine.
  - Converted to an hourly model to capture performance over a typical year
  - Added in steam turbine using data from steam turbine system provider (TurboSteam). Files:
    - "1 - SYSTEM INFORMATION.pdf"
    - "STG_ExtractionMap.pdf"
  - Model implemented in REopt

CHP Detailed Results, no steam turbine

- After providing steam for NOx control, HRSG steam is sent to steam header to displace as much boiler generated steam as possible
- Any excess steam is used for augmentation on the CT to improve fuel efficiency

	CHP All Year	CHP Summer	CHP Winter
Total installed cost ($)	$0 / sunk	$0 / sunk	$0 / sunk
Net present value	-$30,329,000	-$12,743,000	-$17,609,000
Utility electricity (kWh/yr)	65,405,400	123,725,000	94,685,400
Utility electricity reduction (kWh/yr)	87,599,600	29,280,000	58,319,600
Utility electricity reduction (%)	57.3%	19.1%	38.1%
Natural gas consumption (MMBtu/yr)	1,517,921	1,079,072	1,260,849
Natural gas reduction (MMBtu/yr)	-696,148	-257,298	-439,076
Natural gas reduction (%)	-84.7%	-31.3%	-53.4%
Total campus CO2 (metric tons eq.)	108,662	110,449	107,611
CO2 reduction (metric tons eq.)	724	-1,063	1,775
CO2 reduction (%)	0.7%	-1.0%	1.6%
CHP Run Hours/Year	8760	2928	5832

CHP Results with steam turbine extraction

- After providing steam for NOx control, HRSG steam is sent to steam turbine to generate additional electricity
- Some steam is extracted from the turbine at 130 PSI and sent to steam header to displace steam that would otherwise be generated in natural gas boilers
- Any excess steam is used for augmentation on the CT to improved fuel efficiency

	CHP All Year	CHP Summer	CHP Winter
Total installed cost ($)	$0 / sunk	$0 / sunk	$0 / sunk
Net present value	-$33,829,000	-$12,780,000	-$21,027,000
Utility electricity (kWh/yr)	59,008,600	121,952,000	90,062,500
Utility electricity reduction (kWh/yr)	93,996,400	31,053,000	62,942,500
Utility electricity reduction (%)	61.4%	20.3%	41.1%
Natural gas consumption (MMBtu/yr)	1,592,533	1,090,874	1,323,232
Natural gas reduction (MMBtu/yr)	-770,759	-269,101	-501,458
Natural gas reduction (%)	-93.8%	-32.7%	-61.0%
Total campus CO2 (metric tons eq.)	109,870	110,313	108,932
CO2 reduction (metric tons eq.)	-484	-927	454
CO2 reduction (%)	-0.4%	-0.8%	0.4%
Run Hours/Year	8760	2928	5832

CHP Results with condensing steam turbine, max power

- In this mode, steam turbine is run in condensing mode
- After supplying steam for NOx emissions control, HGSG steam is sent to steam turbine. All steam to the steam turbine is condensed (no extraction) to maximize ST generation.
- Any excess steam is sent to the campus steam header

	CHP All Year	CHP Summer	CHP Winter
Total installed cost ($)	$0 / sunk	$0 / sunk	$0 / sunk
Net present value	-$57,042,000	-$20,162,000	-$36,860,000
Utility electricity (kWh/yr)	41,435,000	115,275,000	79,165,400
Utility electricity reduction (kWh/yr)	111,570,000	37,730,000	73,839,600
Utility electricity reduction (%)	72.9%	24.7%	48.3%
Natural gas consumption (MMBtu/yr)	1,929,598	1,204,612	1,546,585
Natural gas reduction (MMBtu/yr)	-1,107,824	-382,838	-724,812
Natural gas reduction (%)	-134.8%	-46.6%	-88.2%
Total campus CO2 (metric tons eq.)	120,194	113,476	116,095
CO2 reduction (metric tons eq.)	-10,808	-4,090	-6,709
CO2 reduction (%)	-9.9%	-3.7%	-6.1%
Run Hours/Year	8760	2928	5832

CHP Results with condensing steam turbine, max steam

- In this mode, steam turbine is run in condensing mode
- After supplying steam for NOx emissions control, the first priority of HGSG steam is to serve the steam header load
- Any remaining steam is sent to the steam turbine to generate additional electricity

	CHP All Year	CHP Summer	CHP Winter
Total installed cost ($)	$0 / sunk	$0 / sunk	$0 / sunk
Net present value	-$37,437,000	-$16,318,000	-$21,156,000
Utility electricity (kWh/yr)	56,644,600	118,744,000	90,906,200
Utility electricity reduction (kWh/yr)	96,360,400	34,261,000	62,098,800
Utility electricity reduction (%)	63.0%	22.4%	40.6%
Natural gas consumption (MMBtu/yr)	1,643,264	1,145,436	1,319,944
Natural gas reduction (MMBtu/yr)	-821,490	-323,663	-498,170
Natural gas reduction (%)	-100.0%	-39.4%	-60.6%
Total campus CO2 (metric tons eq.)	111,545	111,828	109,121
CO2 reduction (metric tons eq.)	-2,159	-2,442	265
CO2 reduction (%)	-2.0%	-2.2%	0.2%
Run Hours/Year	8760	2928	5832

Ground Source Heat Pumps (GSHP)

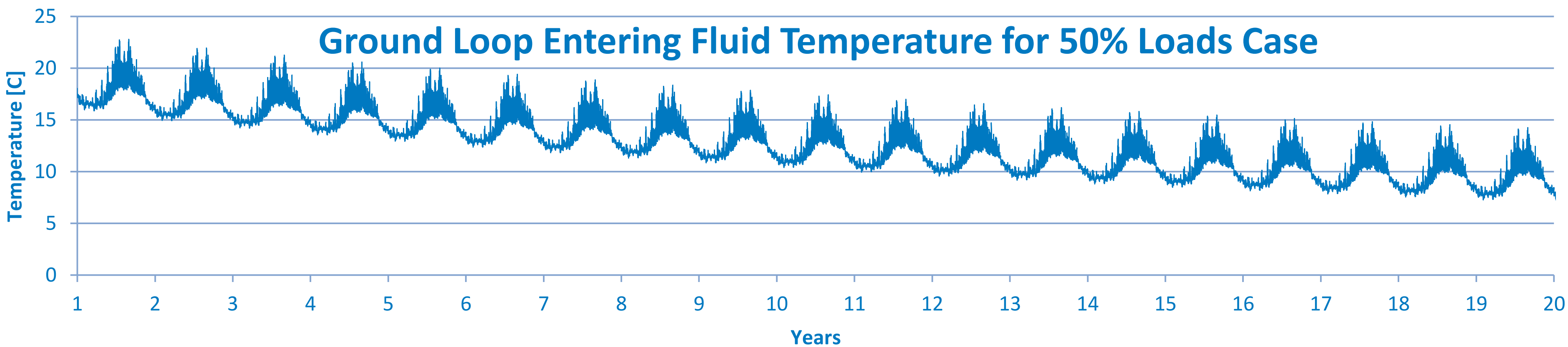
- Considered GSHP for serving 10% and 50% of the total campus heating and cooling loads
- Load profiles for cooling developed from hourly building models using DOE commercial reference buildings, assuming 30% medium office, 30% secondary school, and 40% large hotel. Load profiles from heating are taken as a fraction of the hourly interval heating load data (previously described).
- Cost assumptions:
  - $14.20/foot for ground heat exchange well, plus
  - $10,000/ton total installed costs for all other, including heat pumps, circulating pumps, building retrofits, etc.
    - Costs per slide25: http://www.igshpa.okstate.edu/pdf_files/2014_conf/proceedings/10-16-2014-0100-Terry-Proffer_Josephine-Commons-Affordable-Housing.pdf
  - Costs have high uncertainty based on limited cost data as well as relative difficulty of drilling wells and retrofitting existing buildings heating and cooling systems
- Baseline heating and cooling plant efficiencies
  - 83% steam plant boilers
  - 5.02 COP chiller plant

GSHP Performance Model

- Heat pump
  - Energy Plus performance map
  - Performance at design conditions
    - COP heating 3.2
    - COP cooling 4.2
- Ground loop heat exchanger
  - Model developed from TRNSYS
    - 20 year simulation
    - Sized for min/max ground temperatures 7C/35C, 44.6F/95F
  - Assumed ground parameters (reference: http://www.igshpa.okstate.edu/pdf_files/2014_conf/proceedings/10-16-2014-0100-Terry-Proffer_Josephine-Commons-Affordable-Housing.pdf)
    - density 2500 kg/m3
    - thermal conductivity 8.028 kJ/hr-meter-K
    - specific heat 1.26 kJ/kg-K
  - Well depth 250 ft., spacing 20 ft. centers

GSHP model results

- Cooling load is estimated from commercial reference building models
- Heating load is greater than cooling load (modeled), resulting in gradual decreasing ground temperatures over time
- Better balancing of heating and cooling loads would result in smaller required ground loop surface area and improve economics. However significantly negative economics are not likely to become positive.



Biomass Heat Plant

- Consider economics of a biomass fueled central heating plant to supplement natural gas fired boilers
- Requires special purpose facility for large store of wood chips, wood burning boilers, conveying equipment for loading chips into boilers, emission control system
- Assume direct combustion type steam boilers fueled by wood chips. Possible sources of waste wood are beetle kill forests and municipal tree trimmings
- Fuel could be free if sourced from Xcel or City of Boulder tree trimmings or up to $75/ton (estimated fuel price for NREL biomass heating plant)
- To demonstrate economics, assume a 10,000 kW-thermal / 34.1 MMBtu/hr heating plant to provide baseload heating for the year (highest potential plant utilization)
- Cost assumptions:
  - Capital costs $26,100,000
  - Non-fuel O&M costs $3,012,000/year
  - Fuel costs: $0 and $50/ton
- Capital cost assumptions based on national averages. Higher costs for CU may be realized due to space constraints and architectural aesthetic requirements
- Assumed wood higher heating value 10.7 MMBtu/ton

Solar Water Heating

- Assuming system installation faces south and tilt = latitude
- Typical meteorological year (TMY) weather file to predict daily hot water heat generation
- Costs: $150/ft2 total installed costs, $1/ft2/year O&M
- 25 year useful life

Fuel Cell Combined Heat and Power

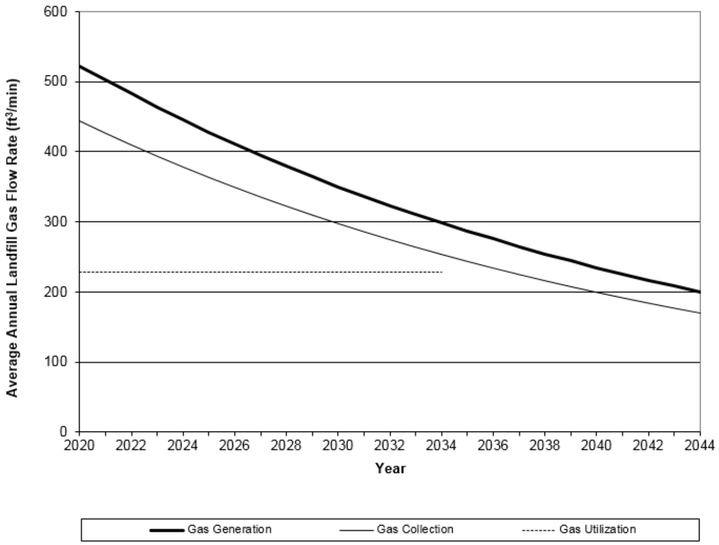
- Fuel cells offer high efficiency electricity generation and waste heat that can be used to generate hot water or low pressure steam
- Natural gas fuel supply
- Capital costs $5217/kW plus $174/kW-year for non-fuel O&M, which includes reformer catalyst and fuel cell stack replacements per budgetary quote from manufacturer.
- De-rates for 5500 ft. elevation per manufacturer:
  - 50 kW reduction in rated power output
  - 1.5% reduction in fuel efficiency
- Estimate economics and CO2 emissions assuming unit runs at full power all year and all available heat is utilized
  - Assume unit is installed where recovered waste heat could be utilized to heat domestic hot water that would otherwise be heated by steam
  - Assume the same standby tariff would apply as the existing CHP plant

Battery Energy Storage

- Simple ‘bucket’ model
- Costs, round trip efficiency, depth of discharge, and service life are reflective of lithium ion type batteries
- 10 year useful life
- Total installed costs:
    - Initial \$1000/kW + \$500/kWh
    - Replacement \$460/kW + \$230/kWh assumed year 10
- 87% round trip AC-to-AC efficiency
- 20% minimum state of charge

Landfill gas

- Nearest landfill is Boulder Landfill, 4.9 miles ‘as the crow flies’ southeast of the East Utility Plant
- Closed in 1992. Estimated production is uncertain and could diminish at rates faster than predicted.
- Assume pipeline can be installed between landfill and East Utility Plant and that a boiler there is retrofitted to utilize landfill methane gas
- Costs, gas production estimates, and gas production decline projection from US EPA Landfill Methane Outreach Program’s *LFGcost-Web v3.2* cost model
- Gas production estimate of 300 ft^3/min with HHV of 475 Btu/ft^3
- Assume gas can be purchased for $1/MMBtu and cost escalates at the same rate as natural gas prices
- Cost assumptions:
  - $1,100,000 Compressor/dehydration unit
  - Pipeline $3,100,000
  - Boiler conversion $145,000
  - $80,000 Annual O&M, including compressor electricity consumption
- Useful life of 15 years assumed per EPA model. Project viability is highly uncertain due to uncertainty of landfill owner’s interest, ability to secure right-away for pipeline, and costs. In addition declining gas production disallows project renewal after initial phase.



Model Description

- NREL's REopt modeling platform for energy system integration and optimization
  - Mathematical model written in the MOSEL programming language
  - With significant site-specific and client-requested customizations
  - https://reopt.nrel.gov/
- Mixed Integer Linear Program
- Solves energy balance at every hour for entire year (8760 hrs./year)
  - Load must be met from some combination of grid purchases, on-site generation, or discharge from energy storage
  - Does not consider power flow or transient effects
  - Has perfect prediction about upcoming weather and load events
- Technology modules based on empirical operating data
  - Must be linearized
- Finds optimal technology sizes (possibly 0) and optimal dispatch strategy subject to resource, operating, and goal constraints
  - Objective function is to minimize life-cycle cost of energy
  - If total emissions are constrained, model will find solution to achieve carbon goal at minimum cost
- Model is solved using commercial FICO Xpress solver on a high-performance Dell Precision workstation with 24 virtual computational cores and 64 GB of RAM

Analysis Disclaimer

- This analysis was conducted using the NREL REopt Model [https://reopt.nrel.gov/]. REopt is a techno-economic decision support model that identifies the cost-optimal set of energy technologies and dispatch strategy to meet site energy requirements at minimum lifecycle cost, based on physical characteristics of the site and assumptions about energy technology costs and electricity and fuel prices. The analysis relies on site information provided to NREL by CU-Boulder that has not been validated by NREL.

- The purpose of the analysis is to identify potential renewable energy projects and their influence on life-cycle costs and campus carbon dioxide emissions. These results should be treated as an initial step, not the final solution. The results are not intended to be the sole basis of investment decisions but rather are intended to inform decision-making that includes multiple other factors not included in the modeling exercise.

- Actual project development would require more detailed assessment that could include: on-site assessments to identify appropriate project sites, including structural and land area review; verification of on-site RE resource through on-site resource measurements; identification of electrical interconnection points with sufficient capacity; confirmation of utility policies for incentives, net metering, interconnection, and buy back of excess electricity; environmental review; and other relevant factors.

- The data, results, and interpretations presented in this document have not been reviewed by technical experts outside NREL or CU-Boulder.

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NATIONAL RENEWABLE ENERGY LABORATORY

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