I. Opportunities in Michigan Wood Energy

OPPORTUNITIES IN

MICHIGAN WOOD ENERGY

a smart fuel choice

Presentation by: Jessica Simons

June 27, 2008
Michigan Energy Fair
Manistee Co. Fairgrounds – Onekama, MI

Southeast Michigan
Resource Conservation
& Development Council

Presentation Overview

- **What is Woody Biomass?**
- Why Wood?
- Sources & Opportunities
- Examples
- Technical Issues
- Helpful Resources

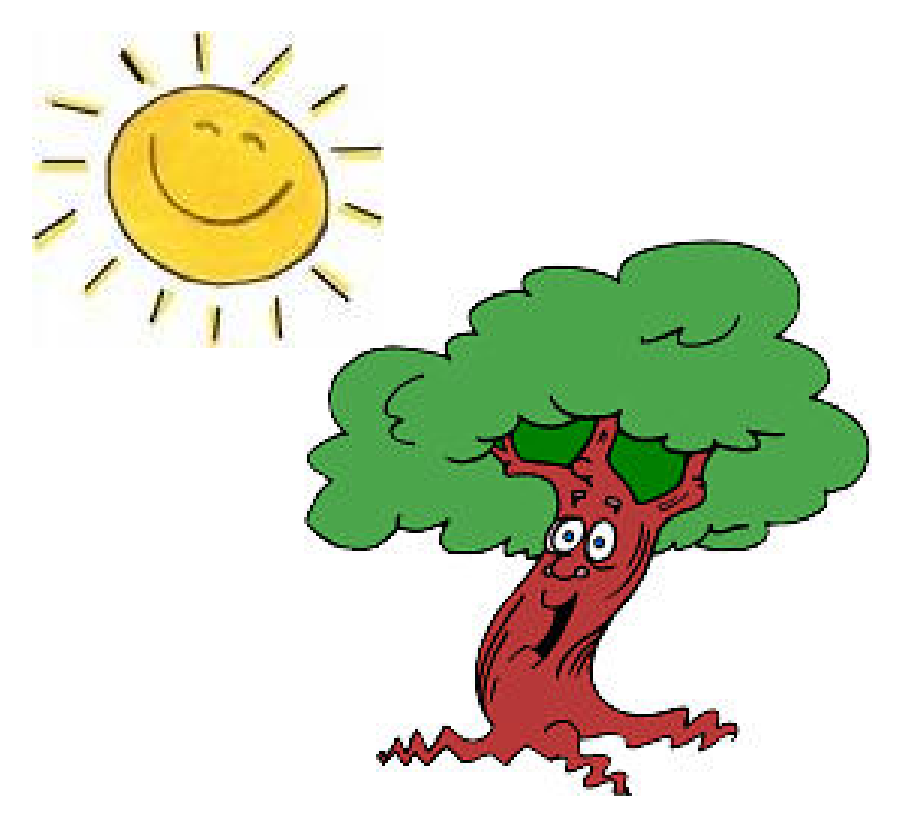
What is Woody Biomass?

- Biomass is simply any organic material – living or dead
- Woody biomass includes entire living & dead trees, brush, stems, logs, & other wood industrial residues

Biology 101 – How Trees Grow

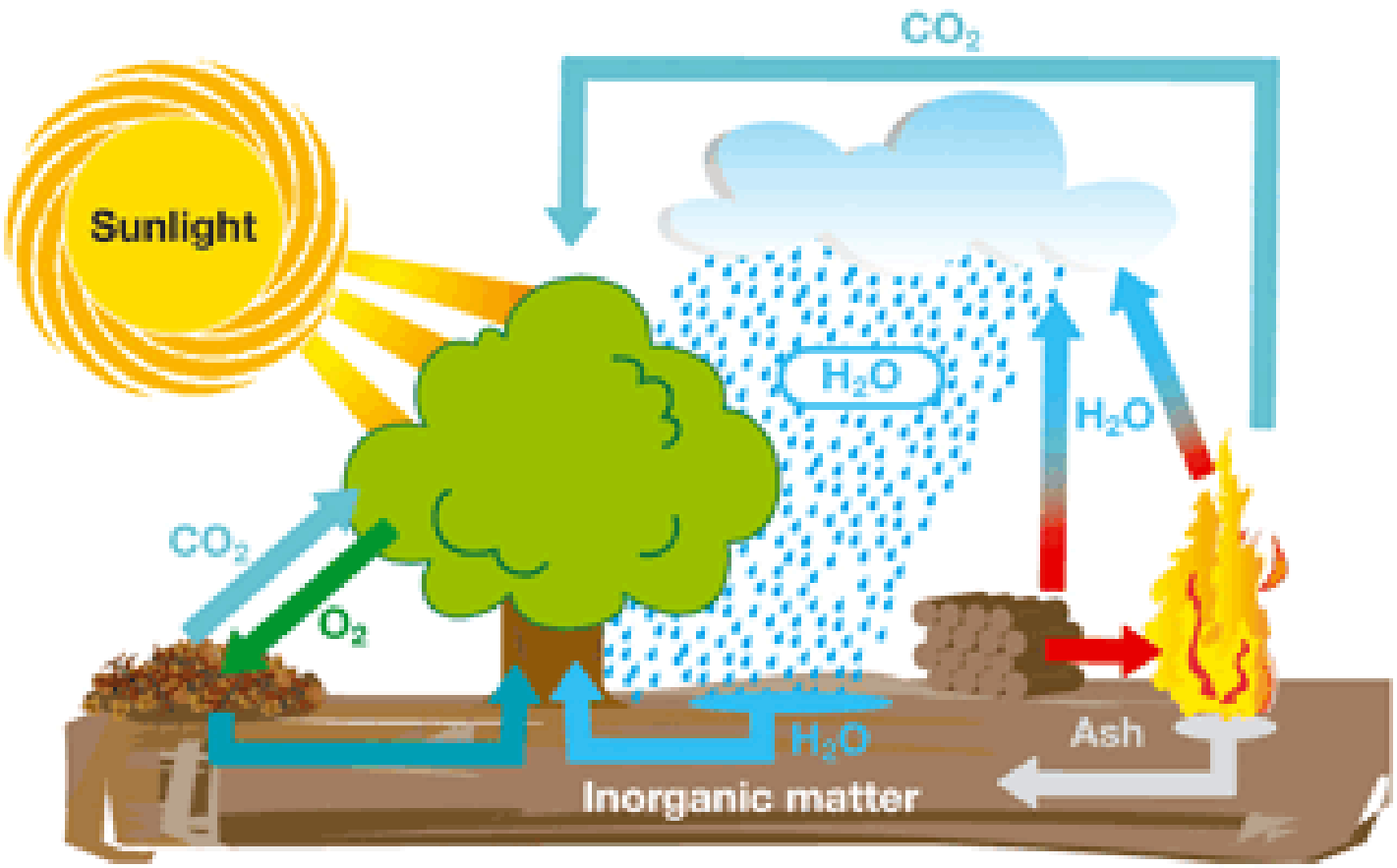
Photosynthesis:

Carbon dioxide + water + energy (sunlight) = glucose/stored energy (mmm… sugar) + oxygen



Combustion:

Stored energy (sugars) + oxygen = carbon dioxide + water + "free" energy



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Wood is Good!

- Renewable
- Local
- Reliable
- Sustainable
- Affordable
- Low carbon emission
- Minimal ash
- Very low metals and sulfur

- Focus of presentation: larger-scale wood boiler systems for institutions and industry
- Can be used through new construction or boiler retrofit

Why Wood?

"Compared to other bioenergy feedstocks, forestry sources have best outlook for feasibility and environmental sustainability."

Corn

extensive cultivation, fertilization, & pest control

Wood

widely available, largely unused, low impact harvesting

From –
Biomass, Biofuels and Bioenergy: Feedstock Opportunities in MI
Robert E. Froese, Ph.D.; February 2007

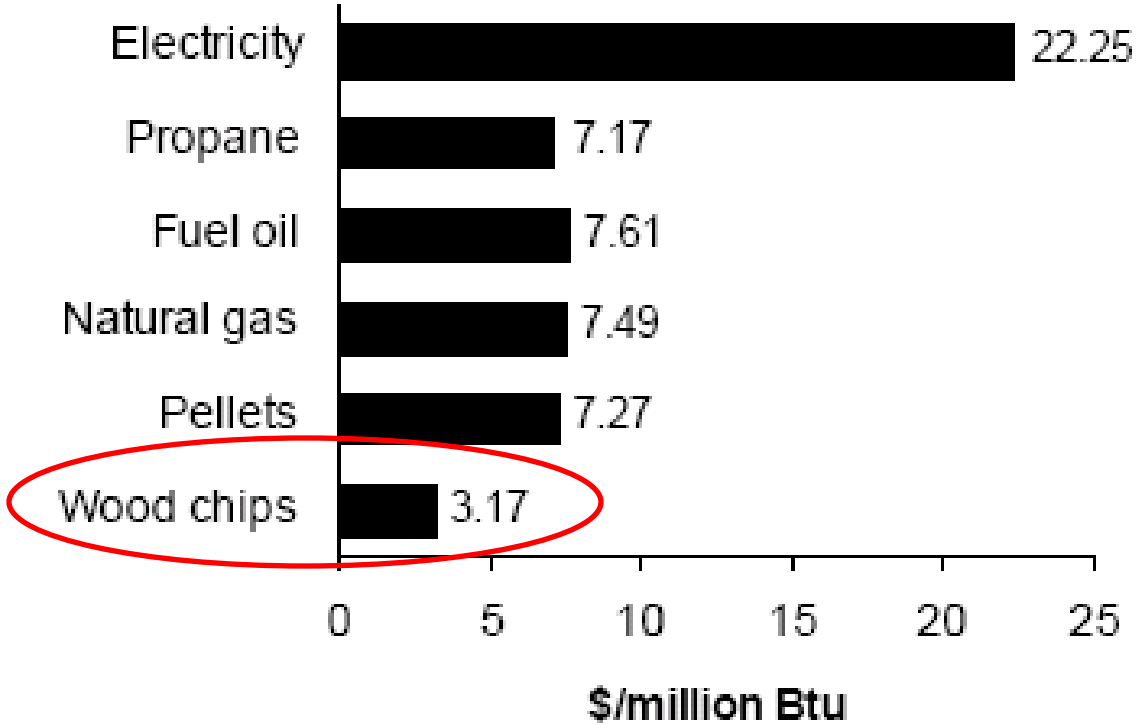
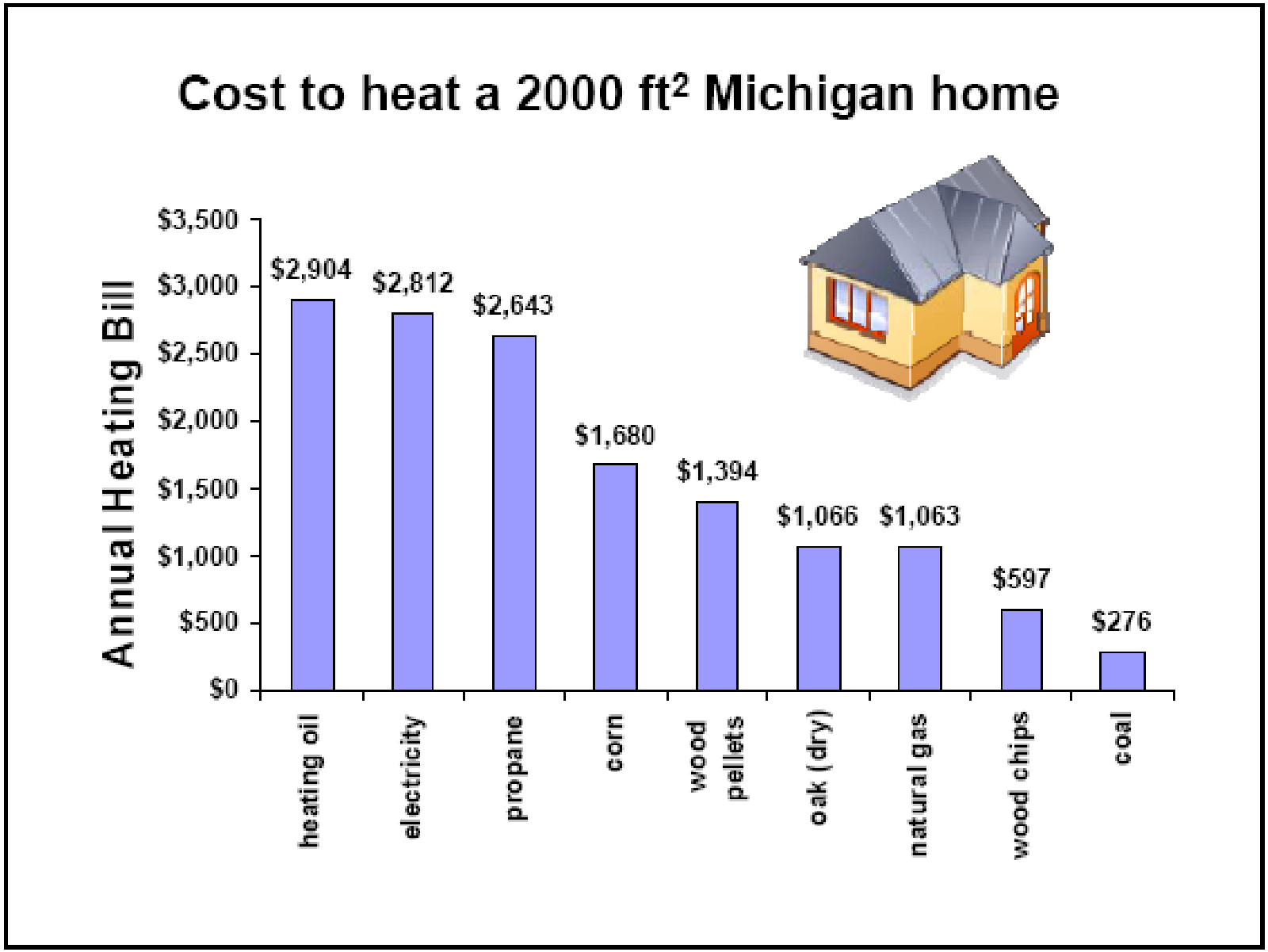


Figure 1. Cost comparisons of fuel types in Wisconsin for large volumes. (1 MW = 3.413 million Btu/h).

Source: Mike Metcalf, Madison Gas & Electric, Madison, WI. May 2004.



Graphic courtesy of Dr. Chris Schilling, Saginaw Valley State University

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Best Sources for Wood?

- **It all depends on where you are –**
  - Urban area? Look for urban sources – city tree removals, pallet recycling operations, clean crates and dunnage
  - Rural area? Look to local forestland owners, forest products companies
- Always keep fuel **quality** (clean!) and **dimensions** (chip vs. ground) in mind when securing sources

Woody Biomass Sources

Urban Tree Removals

Traditionally, communities pay large amounts for BOTH heating fuel and disposal of removed trees.

<u>For example:</u>

Imagine that a city pays –
$25,000/yr to heat city hall
AND
$25,000/yr for wood disposal

What happens to these figures if they get a wood boiler?

Another source: EAB & Other Disasters

- At least 20 million dead and dying ash trees in Michigan
- Cities & residents face high costs for removal, disposal, & replanting

Woody Biomass Sources

Industrial Residues

2005 SE Michigan Wood Residue Inventory

SE Michigan Urban Wood:
both "green" & "brown"

2,600 companies
7.5 million cu yds/yr

Disposal cost = $8.8 million
28% landfilled

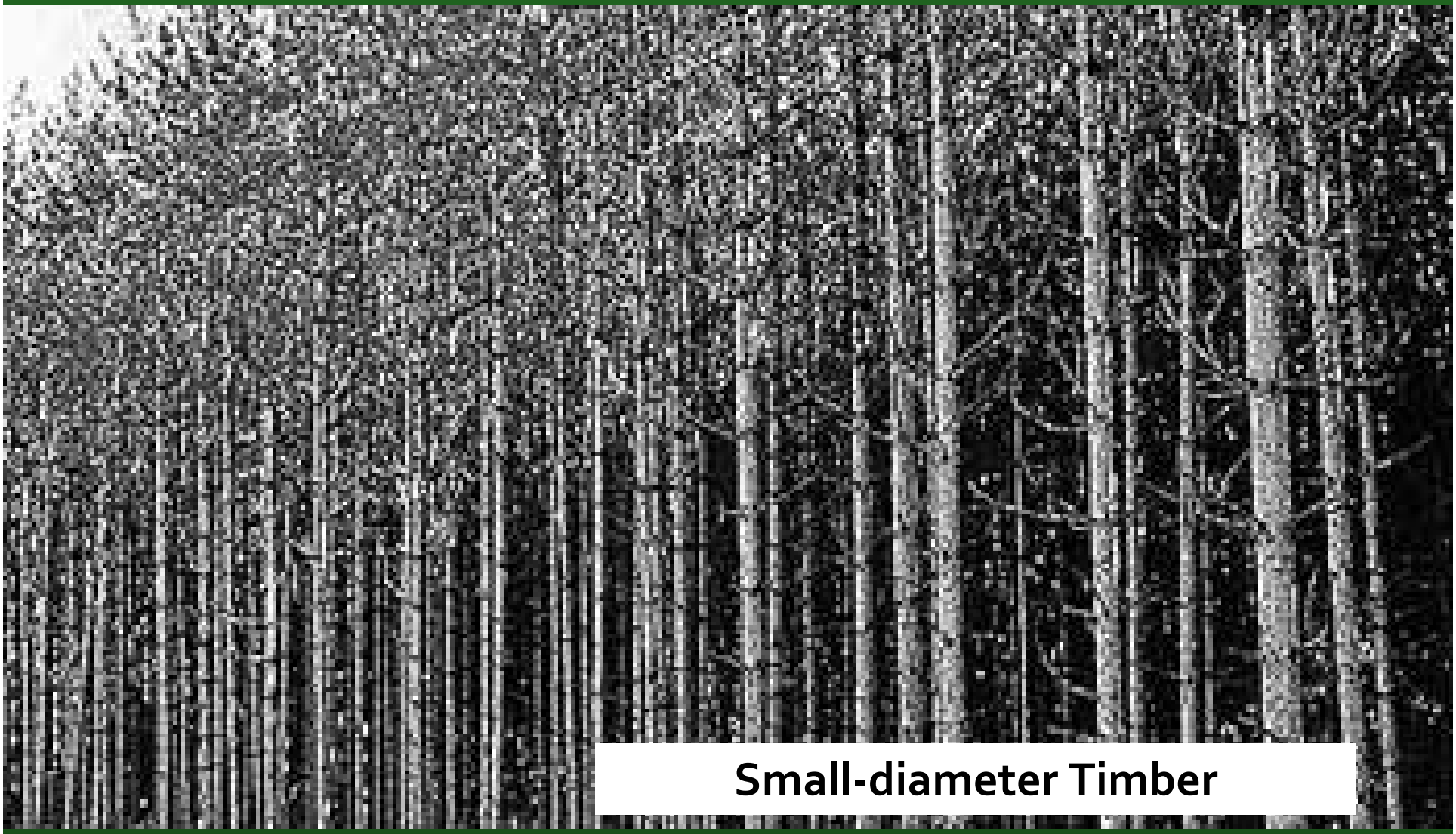
So, how much wood is that, anyway?…

Enough to fill 354 football fields 10 ft deep!

Woody Biomass Sources

Forest Slash & Thinnings

Woody Biomass Sources



Due to Changes in Industry, More Wood is Now Available

Michigan Primary Mill Closures from 2003 to Present:			
Mills	**Location**	**Volume**	**Wood Type**
Pulpmills		*(cords)*	
Menasha Corporation	Otsego	200,000	mixed hardwoods, sawmill chips
SAPPI Fine Paper	Muskegon	250,000	aspen & mix
Particle Board Mills		*(cords)*	
GFP Strandwood Molding Corp.	Hancock	10,000	aspen
Georgia-Pacific Corp.	Gaylord	300,000	mixed hardwoods, aspen, red & jack pine, mill residues

Forecast Bioenergy Feedstock Supply in Michigan in dry tons per year.

Biomass Feedstock		Potential Supply	Currently Available and Unutilized	Available at $25/ton Farmgate Price
Forestry	Sawmill and pulp mill residues	1,764,796	Negl.	405,903
	Logging residues	869,468	869,468	113,031
	Thinning residues	1,875,978	1,875,978	243,877
Forestry Total		4,510,243	2,745,447	762,811
Urban Wood Waste		1,311,382	1,311,382	314,732
Dedicated Energy Crops		4,418,226	Negl.	44,182
Grand Total		10,239,851	4,056,829	1,121,725

Sources: USDA, DOE, Walsh (2006) and Michigan Technological University.

From –
Biomass, Biofuels and Bioenergy: Feedstock Opportunities in MI
Robert E. Froese, Ph.D.; February 2007

POTENTIAL PRODUCTION OF VARIOUS BIOFEEDSTOCKS IN MICHIGAN		
Source	Land Area (million acres)	Annual Yield (in millions of dry tons)
Woody energy crops on idle land	3.2	7.2
Woody energy from excess forest growth	19.3	6.5
Wood biomass from urban trees (annual yield based on 1.5% mortality rate for trees)	2.0	0.2
Mill Residues	--	1.4
Logging Residues	--	1.3
Switchgrass from CRP lands	0.3	1.5
Crop residues	8.0	3.6
Manure, Landfill, & Other	--	Less than 0.6

Sources: USDA Forest Service – Forest Inventory and Analysis for Michigan; USDA Agriculture Statistics Service; Michigan State University; National Renewable Energy Laboratory (compiled by Ray Miller, MSU)

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Example of Potential Wood Energy Savings

Fuels For Schools

Pilot Program: Darby, MT Public Schools

Cost of wood chips (760 tons) =	$ 18,170.00
Cost of boiler operation & fuel study =	$ 4,700.00
Supplemental fuel oil =	$ 1,935.00
2005-2006 Actual Heating Costs =	**$ 24,805.00**

<u>Comparison of projected cost w/ fuel oil:</u>

Historic usage cost of fuel oil =	$115,000.00
(50,000 gal @ $2.30/gal)	
Estimated 2005-2006 Cost Savings =	**$ 90,195.00**

Some Michigan Examples

Calumet-Laurium-Keweenaw Schools
Calumet, MI

Students:	1,200
Size:	251,000 sq.ft.
Years Operating:	17 (since 1990)
Wood Type:	Sawmill/other waste
System:	100 hp boiler (natural gas back-up)
Uses:	Space heat and hot water
Savings:	$100s a day
Response:	"We are totally committed to using wood for fuel."

North Dickinson Schools
Felch, MI

Students:	400
Size:	100,000 sq.ft.
Years Operating:	14 (since 1993)
Wood Type:	Chips
System:	100,000 BTU boiler (propane back-up)
Uses:	Space heat and hot water
Savings:	About $20,000 a year
Response:	"We have a good thing going. Using wood heat frees up a lot of resources for student instruction."

Source: Upper Peninsula RC&D Council's
Biomass Utilization and Restoration Network for the U.P. (BURN-UP)

New wood biomass study for Oakland University:

Annual potential operating savings = ~$1.5 million
Annual wood use = 30-66K tons
1.5-3% of 14-county wood supply
Possible payback within 10 years

Recent Workshop:
Sustainable Energy Project Development for Public Institutions

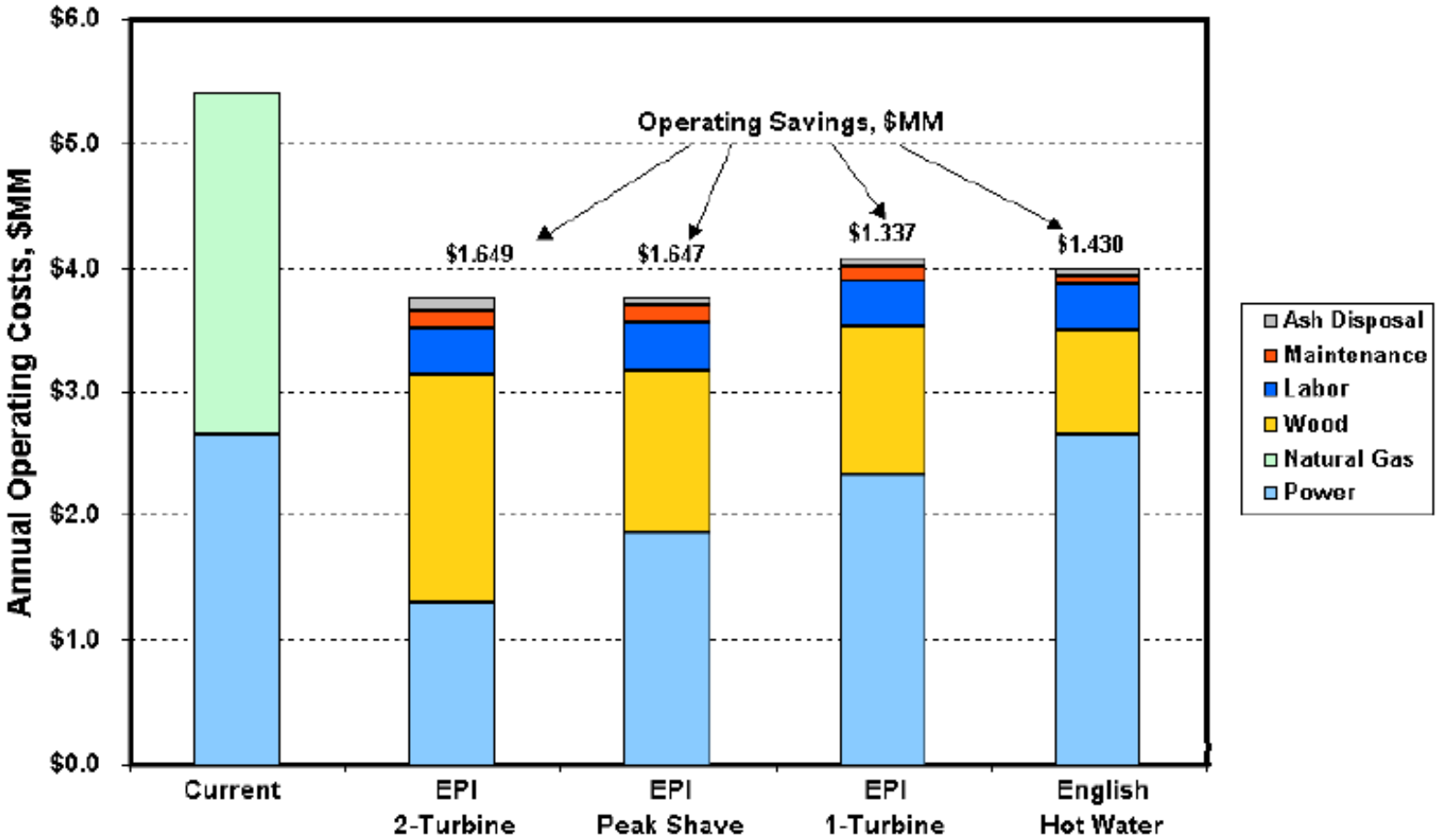
Presentations are online for wood biomass issues:

Resources	Boiler feasibility studies
Procurement	Project air permitting
Transportation	Case studies
Handling	Project funding

http://www.oakland.edu/energy/Energy_Project_Workshop_May_2008.htm

... Projected figures from the Oakland University Study

Operating Costs



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Factors Affecting Woody Biomass Availability

- Private Landowner Values
- Prices
- Sustainability Requirements
- Competing Uses
- Changing Markets

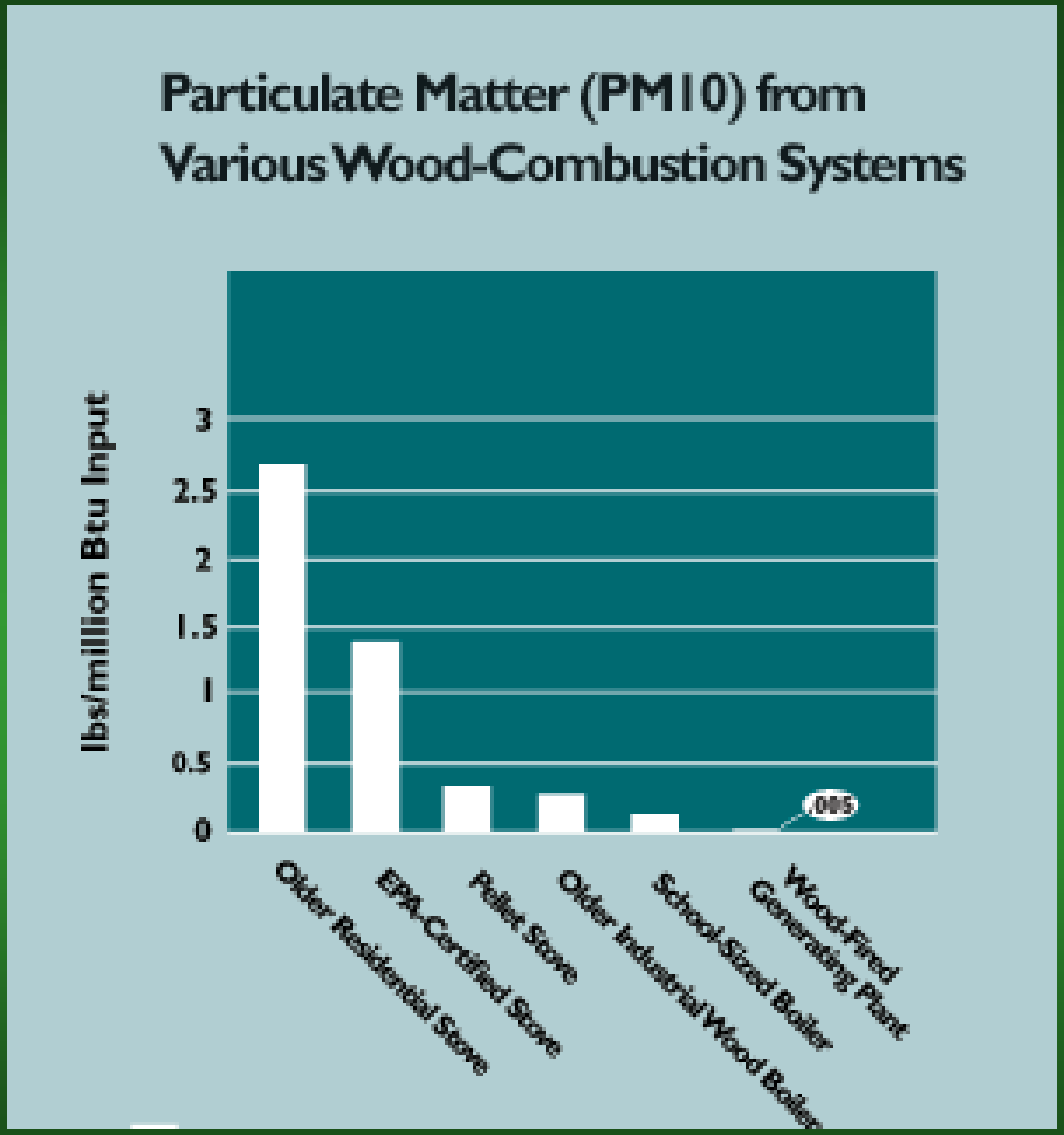
Other Technical Issues

- Location
- Separating residues from wastes
- Landfills and tipping fees
- Transportation
- Harvesting
- Collection
- Processing – drying, chip size requirements
- Maintaining fuel supply
- Handling and maintenance

But What About Air Quality?

Larger-scale
woody biomass
energy production
is NOT
the same as
outdoor wood stoves
or open burning

Incomplete combustion
= Pollution



"Over the course of a year, a large, wood-heated high school (150-200K sq.ft.) may have the same particulate matter emissions as 4-5 houses heated with wood stoves."

Source:
Biomass Energy Resource Center

http://www.biomasscenter.org/information/emissions.html

Measures to Support Clean Air

- Good fuel quality – no contaminated material
- Regular fuel inspections & equipment maintenance
- Tall stack height
- Other equipment: scrubbers & baghouses

Photo of CMU Boiler Plant by Jim Leidel

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www.michiganwoodenergy.org

- **Learn about wood energy options, view resources**
- **See report of 2,000 potential sites for wood energy in MI**
- **Use calculator to estimate savings at your site**

MICHIGAN WOOD ENERGY

a smart fuel choice

Home | Calculator | FAQ | Report | About | Contact

Exploring Woody Biomass Retrofit Opportunities In Michigan Boiler Operations

9/28/2007

The Southeast Michigan RC&D Council selected a team of experts (CTA Architects Engineers, Emergent Solutions, Christopher Allen + Associates, Loracs Creations, and Geodata) to provide a statewide assessment of the potential to integrate wood-fired boiler systems into existing facilities throughout the State of Michigan.

Their final report, *Exploring Woody Biomass Retrofit Opportunities In Michigan Boiler Operations*, includes analysis and conclusions that may help guide strategic wood energy developments statewide. Key features of the report include discussions of the following:

- Recent biomass utilization studies and successful retrofit projects
- Probable costs, savings, and simple payback scenarios for

Download the Report

All are PDF files.

Final Report (1.31 MB)

Appendix A: Statewide Summaries (58 KB)

Appendix B: County Summaries (595 KB)

Appendix C: Figures

Figures 1 - 5 (3.05 MB)

Figures 6 - 10 (3.11 MB)

Figures 11 - 15 (3.19 MB)

Wood Energy Calculator

Contact Information

E-mail

essica.simons@semircd.org

County

Washtenaw

Facility Type

- ○ Office/Retail
- ○ Detention
- ○ Education
- ○ Healthcare
- ◉ Industry
- ○ Power Production
- ○ Residential
- ○ Not Applicable

Boiler Size

Combined Input of Boilers Currently in Your Facility

10000000 (in BTUs)

Current Fuel Type

- ○ Coal
- ○ Electrical
- ◉ Fuel Oil
- ○ Natural Gas
- ○ Propane

Continue

Calculator Continued

Fuel Information

Price of Current Fuel

2.50 ($ per gallon)

Annual Use of Current Fuel

414113 (in gallons)

Projected Price of Wood Fuel

35 ($ per green ton)

Financing

Projected Interest Rate

5 (%)

Finish

Michigan Wood Energy Report

Estimated Total Project Cost: $1,075,000.00

Simple Payback: 1.4 years

Project Financing Information	
Percent Financed	100%
Amount Financed	$1,075,000.00
Amount of Grants	$0.00
Interest Rate	5%
Term	10 Years
Annual Finance Cost - Principal and Interest	$139,217.00

Annual Project Costs					
Cash Flow Descriptions	Unit Costs	Fuel Source Proportion	Annual Fuel Quantities	Fuel Units	Year 1 Costs
Estimated Existing Annual Costs					
Existing Fuel (fuel oil)	$2.50		414,113.00	gallon	$1,035,283.00
Estimated Proposed Wood-Fired System Annual Costs					
Wood Fuel (chips)	$35.00	95%	6216	ton	$217,560.00
Existing Fuel	$2.50	5%	20,706.00	gallon	$51,765.00
Additional Operation and Maintenance Costs					$3,000.00
Total Proposed Annual Costs					$272,325.00
Annual Cost Savings					**$762,958.00**
Annual Finance Cost - Principal and Interest					$139,217.00
Net Annual Cash Flow					**$623,741.00**

Your Current Information

This is the information you submitted via the calculator:

- E-mail: jessica.simons@semircd.org
- County: Washtenaw
- Facility type: Industry
- Combined boiler size: 10,000,000.00 btu
- Current fuel type: Fuel Oil
- Current fuel price: $2.50
- Annual use of current fuel: 414,113.00 gallons
- Projected wood fuel cost: $35.00 / ton chips
- Projected interest rate: 5%

Assumptions

Some standard values were used to make this calculation. These figures are likely to be suitable for your project; however, a site with different values may have a less reliable report. The following assumptions were used:

- Amount of grants: $0.00
- Term of financing: 10 years
- Wood fuel type = chips for systems > 3,000,000.00 btu
- Wood fuel type = pellets for systems <= 3,000,000.00 btu
- Proportion of wood fuel use in new system: 95%
- Proportion of existing fuel use in new system: 5%

[Note: Wood boiler sizes are assumed to be half of the size of existing boilers to maximize efficiency. This size is optimal for meeting the needs of 90-95% of a typical heat load. Existing fossil fuel boilers, which are generally oversized, can still be used to meet infrequent peak load conditions.]

The information provided by the Wood Energy Calculator is a preliminary assessment and should not be used to develop actual project plans. Projected costs and savings are only estimates; no guarantee of actual expenses or benefits is implied.

Projects in Livingston, Macomb, Monroe, Oakland, Saint Clair, Washtenaw, and Wayne Counties are subject to PM-2.5 EPA non-attainment area standards. In most cases, additional air quality measures are required in this region and will likely result in higher costs.

Please see the FAQs and Interpreting Your Results for more information.

Clean Energy from Wood Residues in Michigan

Michigan Biomass Energy Program
Dulcey Simpkins, Coordinator

Discussion Paper
June 2006

http://www.michigan.gov/documents/wood_energy_in_michigan--final1_169999_7.pdf

Confused About Permits?

Monthly Air Permit Application Workshop for First-Time Applicants

OVERVIEW

Are you required to obtain an air permit but not sure how to complete the application?

For most first-time applicants, completing the Permit to Install application is a daunting task. However, submitting a complete and timely application can be more manageable if you know what's expected.

Register on-line at

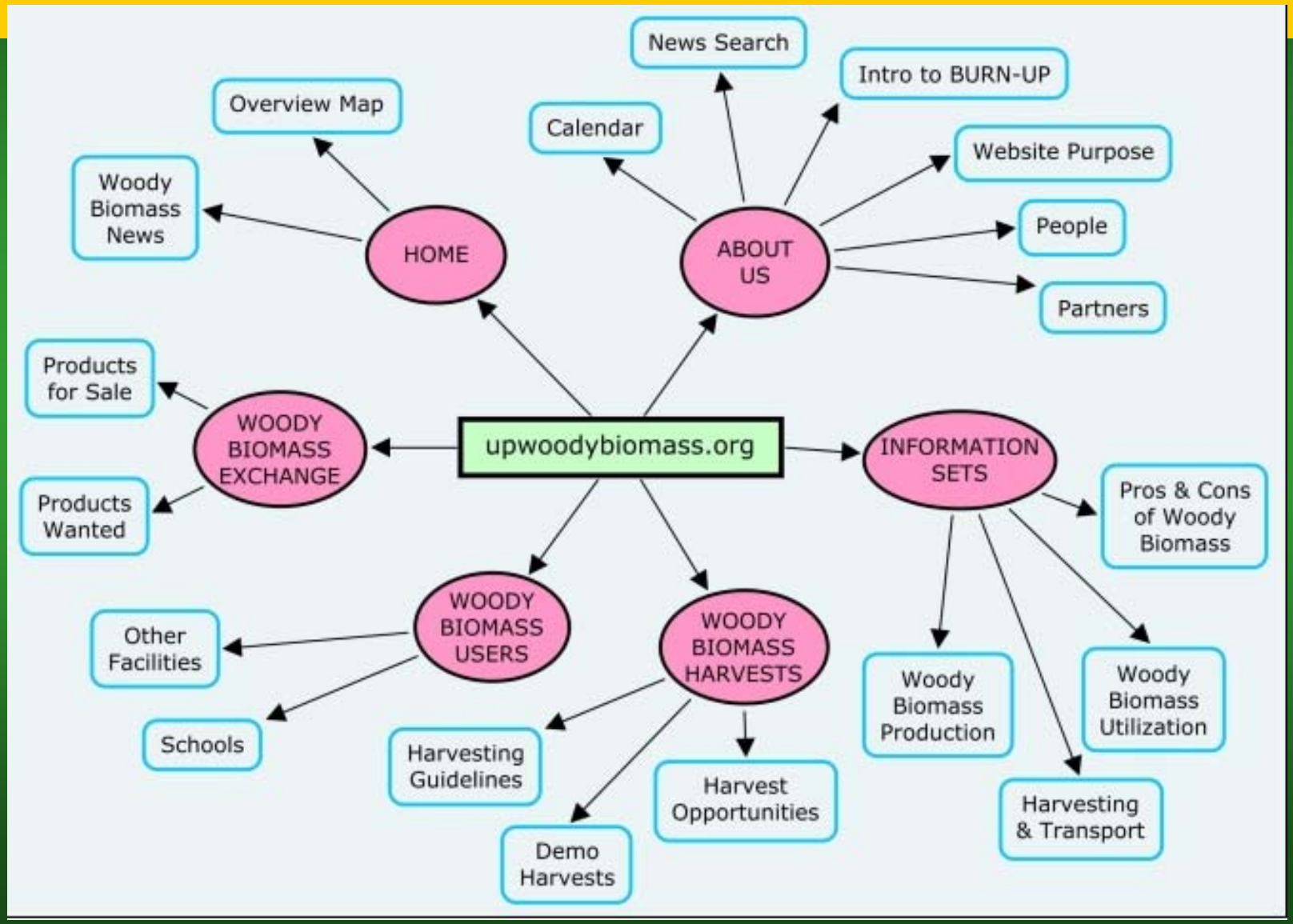
www.michigan.gov/deqworkshops,

click on

"Upcoming DEQ Workshops,"

and scroll down to the ***Permit to Install*** series.

http://www.upwoodybiomass.org/



Coming Soon…

Heating Buildings and Business Operations with Biomass Fuel: A Planning Guide

C. Schilling
Saginaw Valley State University

L. Jacobs, M. Seamon, and T. Dudek
Michigan State University Extension

Coming Soon…

Demonstration Project:
City of Taylor
Heritage Park Petting Farm

These projects are made possible by generous grants and significant technical support from

Wood Education & Resource Center

Northeastern Area Rural Development Through Forestry Program

Economic Action Program

And the Conservation Districts and governments that sponsor the Southeast Michigan Resource Conservation & Development Council

J. Potential Availability of Urban Wood Biomass in Michigan

BIOMASS AND BIOENERGY 33 (2009) 628–634

Available at www.sciencedirect.com

ScienceDirect

http://www.elsevier.com/locate/biombioe

Potential availability of urban wood biomass in Michigan: Implications for energy production, carbon sequestration and sustainable forest management in the U.S.A.

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ABSTRACT

Tree and wood biomass from urban areas is a potentially large, underutilized resource viewed in the broader social context of biomass production and utilization. Here, data and analysis from a regional study in a 13-county area of Michigan, U.S.A. are combined with data and analysis from several other studies to examine this potential. The results suggest that urban trees and wood waste offer a modest amount of biomass that could contribute significantly more to regional and national bio-economies than it does at present. Better utilization of biomass from urban trees and wood waste could offer new sources of locally generated wood products and bio-based fuels for power and heat generation, reduce fossil fuel consumption, reduce waste disposal costs and reduce pressure on forests. Although wood biomass generally constitutes a ''carbon-neutral'' fuel, burning rather than burying urban wood waste may not have a net positive effect on reducing atmospheric CO_2 levels, because it may reduce a significant long term carbon storage pool. Using urban wood residues for wood products may provide the best balance of economic and environmental values for utilization.

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1. Introduction

Recent interest in developing biologically renewable fuel sources has focused renewed attention on utilizing tree/wood biomass for this purpose. In modern times, wood makes up only 7% of global fuel sources, with an estimated 15% of energy used in developing nations and only about 2% in developed nations [1], excluding some developed countries where substantial efforts have been made to use more wood fuel (e.g., Sweden). Much of this wood comes from forests, but a considerable amount also comes from what the Food and Agricultural Organization of the United Nations has termed ''trees outside of forests'' [2]. Generally, the availability of wood from non-forest trees is not well documented [1].

Wood from urban areas is one potentially large source of biomass that appears currently underutilized. Wood biomass from urban areas includes both wood waste generated when wood products are damaged or outlive their usefulness [3] and tree/wood biomass that is liberated when urban trees are taken down or parts of woody vegetation are trimmed [4]. At global and national scales, it appears that urban wood biomass may offer a potentially large source of wood that could be reused, burned for fuel or otherwise recycled [1,3,4]. However, some important questions remain regarding how available urban wood biomass resources are and what are the implications for trying to make use of them. In particular, it is important that these questions be answered at local or regional scales where wood utilization potential is most practically assessed.

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Here, new data and analysis on the potential availability of biomass from urban trees in a 13-county area of Michigan, U.S.A. is combined with existing data from several other sources to examine the potential of urban tree removals and other urban-generated sources of wood biomass to supply locally generated bio-based fuels and primary and secondary (recycled) wood products. The critical points of discussion focus on the implications of urban wood utilization for energy production, carbon sequestration and sustainable forest management at the scale of regional and national economies.

2. Regional study: urban tree biomass in southeastern lower Michigan

2.1. Study area

A regional assessment of standing urban saw timber in a 13-county region of southeastern lower Michigan (Fig. 1) was recently completed [5]. The study area was comprised of urban portions of the original 13 counties quarantined by the Michigan Department of Agriculture due to the recent introduction of the exotic wood-boring beetle, the emerald ash borer (EAB, *Agrilus plannipennis*). This specific study region was chosen because EAB has caused the death of estimated millions of ash (*Fraxinus* spp.) there [6], which has focused specific attention on the issue of better urban wood utilization. This study area should be reasonably representative of other similar urban areas in the Upper Midwest of the U.S.A.

2.2. Urban tree wood biomass estimation

Measurements of 1887 trees and stumps on 418 plots in 76 randomly selected urban neighborhoods in the study area [5] were used to estimate urban tree biomass. Biomass equations for urban-grown trees are not widely available, as they are for forest-grown ones. Forest-derived biomass equations overestimate the biomass of urban (open grown) trees by about 25% leading to a rule of thumb of 0.8 units of urban biomass per unit of biomass predicted for a forest-grown tree of comparable size and species [7]. Using a general, composite equation that combines the variety of species occurring in urban areas together into a single predictive equation with species-specific adjustments is considered superior to using many different equations for different species derived from different sources [7]. Thus, general whole tree above-ground biomass models for forest-grown hardwoods and softwoods [8,9] were adjusted to be 80% of predicted values to obtain general whole tree biomass equations for urban hardwoods and softwoods, respectively.

Whole tree biomass was portioned into bark and leaves via urban tree leaf biomass equations [10] and species-specific bark factors [11] and then into wood via subtraction. Wood and bark biomass estimates were adjusted for individual species with heavier or lighter than average wood, using published values of wood and bark specific gravity for each species [11]; an inflation/deflation factor was used that was the ratio of the specific gravity of the species in question divided by the average specific gravity for all of the species considered. Only urban trees $\geq$20 cm diameter at breast height (DBH) were measured in urban neighborhoods [5], so the additional biomass contributed by smaller trees was estimated by regression, contributing an additional 3%. Hence, the final total dry wood biomass (metric tonnes, t) estimates were the total amount for trees $\geq$20 cm (DBH) in urban neighborhoods, inflated by 3% to account for the additional mass of dry wood per urban ha stored in smaller trees.

2.3. Scaling up individual tree estimates to the regional scales

Tree biomass estimates (t ha^{-1}) were scaled up to the regional landscape scale by expanding neighborhood estimates to the total land area estimated in an urban condition. Two common methods are utilized for urban area estimation: (1) use political boundaries such as city limits or census districts and include any trees or forests in urban zones [12] or (2) use classified satellite images to estimate urban areas remotely [5,13]. Method 2 is overly conservative [5] and biased by confusion between the conflicting tasks of identifying urban areas on satellite images while simultaneously identifying tree cover at the same location [13]. Urban treed areas for this study were computed using a U.S. Census Bureau definition of urban area [14] and percent urban tree cover for Michigan [12]. The ratio of urban tree biomass per % tree cover per ha was used to scale up urban biomass to the census area. Urban tree cover for the study area was previously too low due to use of the satellite method [5] and so revised estimates for urban sawn wood products available from urban trees were also developed, scaled up in the same way as the new biomass estimates.

2.4. Estimating potential annual yield from urban trees

In order to calculate the potential availability of urban wood biomass on an annual basis, it was necessary to estimate the rate at which urban trees would become available for utilization. Most studies of potential wood biomass availability focus on growth rates of different vegetation types [1]. Since urban trees in the U.S. are not typically planted as crops or harvested live, a reasonable estimate of availability was derived from the mortality rate of urban trees; about 2% of the standing volume of trees for this study area [5].

2.5. Estimating current utilization

Current utilization of wood residues was derived from interviews with 1500 companies within the same 13-county region [15].

2.6. National level estimates

Data from this study were combined with a national study of tree cover and urban forest carbon sequestration [12] to extrapolate regional results to the U.S.A.; carbon was converted to total biomass assuming 0.5 t carbon per t biomass and then to above ground biomass deducting the 21% of mass in roots [12]. National utilization estimates were extrapolated via data describing land filling of US wood [4]. Availability of

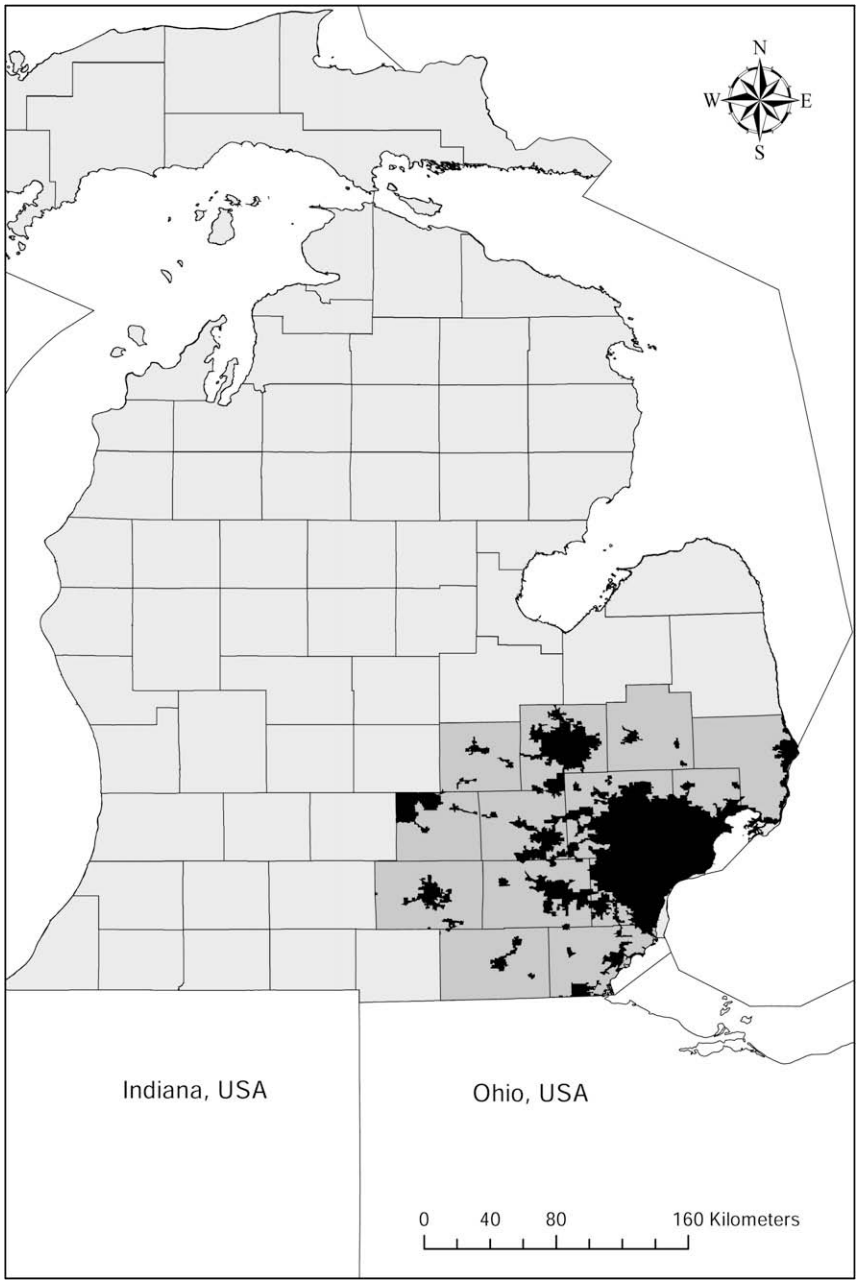

Fig. 1 – Urban U.S. Census areas (black) in the 13-county study area (medium gray) in Michigan, U.S.A. (light gray).

urban tree biomass was also assumed to be 2% of standing stocks per annum at the national level.

3. Results - biomass from urban tree removals

3.1. *Biomass from urban tree removals in 13 counties in Michigan*

The 2.2 million ha study area includes about 73% of all urban area in Michigan and about 2% of U.S. urban area (Table 1). Estimates of annual yield of wood biomass in the study area range from about 367 to 517 thousand dry tonnes of biomass from routine removal of dead and dying urban trees, with the variability in the estimates (standard error, Table 1) stemming largely from the high variability in tree size and coverage in different urban neighborhoods within the region. The bulk of this urban tree biomass is wood (85.7%), with the remaining material being bark and leaves, 11.8% and 2.5%, respectively. Note that these annual yield numbers were not based on catastrophic losses of ash trees in the study areas due to EAB, which are already accounted for, but instead were based on an expected average background rate of tree removal from mortality of currently standing trees.

The annual yields of wood biomass from dead and dying urban trees described are the equivalent in energy content to between 1.2 and 1.7 million barrels of oil per year,

Table 1 – Biomass (dry metric tonnes, t) and sawn wood products (m^3) potential from urban tree removals in a 13-county area of Michigan and in the conterminous U.S.A.

	Michigan, U.S.A., 13-county study	U.S.A.
Area		
Urban area (ha)	545,690[b]	28.1×10^6[a]
% Tree canopy cover[a]	29.7%	27.1%
Biomass[c]		
Mean ($t\,ha^{-1}$)	40.5 [6.9]	39.6
Standing (t)	22.1×10^6 [3.8×10^6]	1112×10^6
Ann. yield[d] ($t\,ha^{-1}\,y^{-1}$)	0.81 [0.14]	0.79
Ann. yield[d] ($t\,y^{-1}$)	442,009 [75,142]	22.2×10^6
Barrels oil[e] y^{-1}	1.44×10^6 [2.4×10^5]	72.6×10^6
People's oil[f] y^{-1}	57,302 [9741]	2.8×10^6
MW electricity[g] y^{-1}	97.5 [16.5]	4836
Sawn wood products		
Mean ($m^3\,ha^{-1}$)	23.2 [4.0]	23.2
Standing (m^3)	12.7×10^6 [2.2×10^6]	651.9×10^6
Ann. yield[d] ($m^3\,y^{-1}$)	253,674 [43,125]	13.0×10^6
Homes[h] y^{-1}	5565 [946]	285,189

[ ] Standard error of estimates.
a Area and % tree cover for 48 states excluding Alaska and Hawaii; includes water bodies in area estimates (see Ref. [12]).
b Census urban area (see Ref. [14]).
c MI 13 county biomass includes wood + bark + leaves. USA biomass estimates were computed as 2 times t C (see Ref. [12]), assuming non-root = 0.79*total.
d Dead and dying trees (see Ref. [5]).
e Based on 18,960 BTU per kg oven dry wood and 5.8 million BTUs per barrel crude oil; 1 BTU = 1.055 kJ (see Ref. [16]).
f Based on 20.8 million barrels of oil consumed per day (see Ref. [17]) by 302 million people (see Ref. [14]).
g Based on Oak Ridge National Laboratories estimate of 4535 t per MW electricity (see Ref. [18]); 1 US ton = 0.907 t.
h Based on 13,000 board feet of framing lumber per average US home (see Ref. [19]), converted to m^3 equivalents.

supplying the annual oil consumption equivalents of about 57,300 people, or the equivalent of one 97.5 MW power plant (Table 1). This 13-county region already supports a 35 MW power plant that was designed specifically for burning urban wood [20], but this capacity could be increased (Table 1). Alternatively, substantial amounts of sawn wood products, which have a dramatically higher commercial value than fuel wood, could be derived from routine urban tree removals in the study region (Table 1), the dimensional lumber equivalent of over 5500 average-sized residential homes per year.

Interviews with 1500 regional companies regarding wood residue utilization in the study region indicated that about 58% of wood residues were discarded annually, including pallets, skids, shipping crates, edgings and cutoffs, chips, shavings and sawdust, construction debris and tree trunks limbs and stumps [15]. About 48% of the discarded material went to landfills, or about 28% of the total wood residues [15].

3.2. *Biomass from urban tree removals in U.S.A.*

The possibility to recover utilizable biomass from urban trees in the U.S. appears large. Extrapolating the regional study results to the national level (Table 1, and see Ref. [12]), biomass from routine urban tree removals in the U.S. is estimated to be about 22.2 million tonnes per year (Table 1). For the U.S. as a whole, these annual yields could supply an estimated 2.8 million people with electricity annually, or the equivalent of about 72.6 million barrels of oil per year (Table 1). Alternatively, an equivalent amount of wood to build more than 285 thousand homes per year could be derived from urban tree removals across the U.S.A.

Over 180 million tonnes of municipal solid waste per year are generated and about 21 million tonnes of this is wood waste (11.8%) [4]. The two main pools that comprise this wood waste are wood from wood products (42.4% or 9 million tonnes) and urban trees and wood yard residues (57.6% or 12 million tonnes) [4]. The latter includes whole trees and parts of trees and shrubs removed from urban areas. Combined with the U.S. annual yields presented here (Table 1), approximately 54% of the urban trees and woody yard residues available may be going into U.S. landfills.

4. Discussion

4.1. *U.S. potential for increased urban tree and urban wood waste recovery*

The results of this study suggest that the potential for recovering usable biomass from urban trees and wood waste is substantial within the 2.2 million ha study region in Michigan. When combined with the national scale data, these data suggest that urban wood biomass is an abundant and underutilized resource across the U.S.A., with significant enough amounts available to make an impact at local or regional economic scales. It has been estimated that only about 15% of urban wood waste is burned for energy annually [1], leaving the bulk of material available for expanding fuel supply or for other uses. An estimated 816 thousand tonnes of pallet material alone is land filled per year in the U.S.A., which represents about 85% of discarded pallets; of the remaining 15% utilized about 39.3% is used for fuel [21]. An estimated 245,000 homes per year demolished on purpose or through disaster in the U.S.A. [19]. This study suggests that there is enough wood from annual urban tree removals to rebuild all of these homes (Table 1). Clearly, recovery of urban wood biomass from trees and discarded wood products could be increased.

4.2. *Economic considerations for enhanced urban wood biomass utilization*

The logistics of actually gathering up and utilizing urban wood waste and urban trees may seem daunting relative to, e.g., harvesting a bioenergy crop from point sources such as plantations. Urban wood biomass is generally an extensive rather than intensive resource, although land clearing and random destructive events can supply substantial amounts over short periods of time. For example, from 2002 to 2005, about 200,000 *additional* dry tonnes of ash tree biomass was supplied to the Genesee Power Station, within the study region, from widespread death of ash trees in the Detroit-

Metropolitan area, providing an additional 22.4 MW of electricity [20]. However, the latter was orchestrated in part, via government incentives to sanitize infested trees [20]. Thus, under typical conditions, incentives in the form of avoided costs or direct gains may be necessary to make collecting urban wood waste attractive. For example, a nationwide average cost reduction of about $9 per tonne was reported in the U.S.A. in 1995, if pallets were simply disposed of at a wood waste processing facility ($26 per tonne) instead of land filling as is ($35 per tonne) [21].

When wood biomass is a product in demand, as well as a disposal cost to be avoided, the economics of urban wood biomass becomes even more appealing. The "total benefit" of using urban wood waste can be calculated as the costs avoided plus the unit price for the material; it ranges from $48 to $132 U.S. per tonne across the U.S.A. (Table 2). In regions where the cost of land filling is high, generally through a combination of high land values and environmental regulations, the general benefit of utilizing wood waste increases regardless of the market value for the biomass (Table 2). Obviously, some wood waste is not strictly recyclable and is destined for landfills, because it is contaminated, such as in the case of demolition or natural disaster cleanup, where trees and wood become hopelessly mixed with soils, rubble and other materials; extracting utilizable wood from such materials can have a very high cost (see Ref. [19]).

The U.S. national trend has been for continued steady increases in land filling fees nationwide, tripling over a twenty year period from 1985 to 2005 [23]. Surely this will continue to make conversion of wood waste to usable biomass more attractive. At a bare minimum, the cost of land filling wood, which does not compress well and takes up large volumes relative to more compressible waste, could be offset, even if burning, sawing or other uses of urban wood waste and trees are not profitable by themselves (Table 2). In highly populated regions of developed nations, where land is limited for land filling waste or otherwise (e.g., Taiwan, the Netherlands), offsetting land filling costs through urban wood utilization may amount to an enormous savings as well as a boon for land conservation.

If transportation costs are also added into the equation, the value of urban wood biomass for energy is even greater, because wood waste is produced in its greatest abundance in areas where energy demand is the greatest. The best case scenario for wood waste combustion is when the waste is burned directly on site, as is practiced in paper mills [24]. The average hauling distance traveled to dispose of urban wood waste (including discarded trees) was 16 km in the 13-county study region [15]. Thus, urban wood waste can claim the additional large benefit of being a biomass resource that is generated near the center of demand.

Fuel may not be the best economic choice for urban wood utilization. A power plant that burns wood biomass in the U.S.A. can only afford to pay a relatively low price when competing with power or heat generation supplied by fossil fuels, meaning that other biomass users (such as the mulch or pulpwood industries) may be able to outbid energy producers for urban wood biomass. Data from the Oak Ridge National Laboratory [22] suggest that much of the potentially available biomass for fuel will come from urban wood waste as long as the value of biomass remains low (<$22 per dry tonne) (Table 2). A substantial amount of urban wood biomass from trees is of saw timber quality (Table 1, and see Ref. [5]). It would be extravagant to burn up saw grade wood, wherever it could be cost effectively extracted from tree removals or recycled from discarded wood products, unless the price for biomass fuel were to increase substantially.

4.3. *Implications for carbon sequestration*

One of the many benefits touted for using urban wood waste [3] is enhanced carbon sequestration attributable to a reduction in virgin material being utilized, as well as the fact that burning wood is intrinsically carbon neutral, because its

Table 2 – Total benefit and predicted supply rates of urban wood waste in the U.S.A. at different market prices, with consideration of regional land filling costs.

Region	Land filling costs[b] (US$ t^{-1})	Market price of biomass[a] (US$ t^{-1})[b]			
		<$22	<$33	<$44	<$55
		Percentage of available biomass comprised of urban wood waste at market price[a]			
		92.5%	35.0%	11.7%	7.2%
		Total benefit of urban wood biomass (US$ t^{-1}) (cost avoided plus profit)			
South Central	$26.53	$48.58	$59.60	$70.63	$81.65
West Central	$26.60	$48.65	$59.68	$70.71	$81.73
South	$34.15	$56.20	$67.22	$78.25	$89.27
Midwest	$38.54	$60.60	$71.62	$82.65	$93.67
West	$41.61	$63.66	$74.69	$85.71	$96.74
Mid-Atlantic	$51.04	$73.09	$84.11	$95.14	$106.16
Northeast	$77.76	$99.81	$110.84	$121.86	$132.89
Nationwide	$37.81	$59.86	$70.88	$81.91	$92.93

a From Nationwide 1999 estimates by Marie Walsh at Oak Ridge National Laboratories (see Ref. [22]) converted from US$ per US ton; 1 US ton = 0.907 metric tonnes.
b NSWMA Research Bulletin 05-3 (see Ref. [23]), also converted from US$ per US ton.

ultimate energy source is solar. While all wood-derived sources are superior in this regard to fossil fuels, consumption of wood from different sources will have a different impact on net CO_2 sequestration, because the life expectancy of wood carbon (i.e., decomposition rate) is not equal for wood in all of its forms [25].

Table 3 shows the possible implications of utilizing woody biomass for fuel production from different sources. Here, this impact is specifically quantified as a CO_2 *impact factor*, which is the net flux rate divided by the size of the pool, i.e., the relative impact of liberating carbon from a biomass pool. This analysis (Table 3) suggests a much higher penalty, measured in terms of net relative loss in CO_2 sequestration, for burning rather than burying wood residues in landfills. When this impact is considered in the narrow context of carbon markets, this may dramatically increase the social cost of capitalizing on the fuel potential of urban wood residues. However, it is equally clear that there are considerable social and environmental costs associated with land filling wood, e.g., decreasing open land area available for other uses, which casts some doubt on the value of burying wood waste to offset atmospheric carbon levels. Recovering sawn wood products from urban wood biomass, rather than burning or burying it, may provide superior carbon sequestration benefits when co-realized with the increased feedstock value for sawn- versus fuel- wood products.

4.4. *Implications for sustainable forest management*

Increasing global demand for a wide range of wood products [26,27] has strong implications for sustainable forest management. Under current global trends in population expansion (e.g., U.S.A., see Ref. [28]), the associated contraction of forested lands available for harvesting, and concerns regarding the ecological sustainability of expanding forest biomass utilization [29], the possibility for using wood from forests for biomass energy is constrained [30]. Urban land expansion increases the demand for wood and necessarily increases the pool that constitutes urban wood biomass, so, increasingly, urban wood will need to be utilized to absorb some of the burden from forests. Clearly the potential is there; since 2000, the volume of urban tree and woody yard residues now exceeds the volume of wood harvested from U.S. National Forests [4].

How much urban area it would take to replace wood biomass that would be extracted from a forested area of equal size? Data from U.S.D.A. Forest Service Forest Inventory and Analysis (FIA) Program [31] were used to estimate that the woody biomass growth rate on average timberlands in Michigan is about 3.2 t ha^{-1} y^{-1}, which falls within the typical range of 2.3–4.5 t ha^{-1} y^{-1} reported for the U.S.A., and is considerably lower than the typical range for pulpwood pine plantations 6.8–9.1 t ha^{-1} y^{-1}or intensively managed energy crop plantations with growth rates of 15.8–22.7 t ha^{-1} y^{-1} [18]. At an estimated 0.8 t ha^{-1} y^{-1} (Table 1), the yield rate of urban trees through mortality is surprisingly high relative to growth rates achievable for live trees in forests; about 25% of the growth rate on timberlands in Michigan and about 4% of that yielded from high energy plantations.

This relatively high yield from dead and dying urban trees is logical because there are well established and continuing to expand urban forests comprised largely of more open-grown trees that have growth rates which exceed that of the average forest-grown tree [12]. Perhaps most critically, some level of yield is all but guaranteed, as a steady proportion of dead and dying trees in urban areas will be removed for reasons of safety or aesthetics [32], unlike dead and dying forest-grown trees, which, while offering a potentially large supply of wood biomass [1], will not likely be salvaged for reasons relating to ecological sustainability [30].

Translated into area, the results presented here suggest that the potential wood biomass from annual tree mortality on 4 urban ha is equivalent to the average annual growth found on 1 ha of Michigan timberlands. About 31% of new growth is actually removed each year from Michigan timberlands [31], about 1.0 t ha^{-1} y^{-1}. By contrast, the actual removals rates for standing live and standing dead trees was estimated at 3.8% and 8.4% per year, respectively in Baltimore, Maryland, U.S.A. [32], indicating that dead urban trees are not typically removed right away, i.e., the potential availability of dead tree wood biomass described here is not currently capitalized. The total area of timberlands in Michigan is about 10 times larger (7.59 million ha of timberlands) [31] than the 749 thousand ha categorized as census urban in Michigan [12]. Thus, about 8% of the statewide average annual dry biomass removed from Michigan's timberlands (7.5 million t y^{-1} over the last inventory cycle from 2000 to 2004) [31] could be supplied by the removal of dead and dying trees from the Michigan's urban areas.

Table 3 – U.S. Carbon pools, fluxes and potential CO_2 impact factor of wood removal from those pools.

Carbon pools[a]	Stocks%	Net change (%)	CO_2 impact factor (Net/Stocks)
Landfilled trees/trimmings[b]	4.1%	26.9%	6.59
Landfilled wood products	3.0%	19.7%	6.59
Wood products	2.0%	7.3%	3.66
Downed dead wood	3.0%	8.0%	2.68
Urban trees[c]	1.2%	1.5%	1.16
Forest trees	29.7%	34.4%	1.16
Forest floor	8.0%	0.7%	0.09
Forest soils	48.0%	1.5%	0.03
Forest understory	1.0%	0.0%	0.00

a Modified from Woodbury et al (see Ref. [25]); total biomass pool sizes recalculated to equal 100%.
b Landfilled woody yard trimming are 1.36 times the pool of landfilled wood products (see Ref. [4]).
c Assumes 4.4% of carbon in trees is in urban trees (see Ref. [12]).

5. Conclusions

Urban trees and wood offer a modest, yet substantial and reliable amount of wood that could contribute significantly to regional and national bio-based economies. Biomass derived from urban trees and wood waste offers the potential for: 1) deriving local wood products from urban trees, 2) deriving

locally generated fuel sources for power and heat generation, 3) reducing fossil fuel consumption, 4) reducing waste disposal costs, and 5) reducing pressure on forests.

Although wood biomass generally constitutes a "carbon-neutral" fuel, burning rather than burying urban wood waste may not have a net positive effect on reducing atmospheric CO_2 levels, because it may reduce a significant long term carbon storage pool. Using urban wood residues for wood products may provide the best balance of economic and environmental values for utilization.

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K. Quantifying Urban Saw Timber Abundance and Quality in Southeastern Lower Michigan

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Quantifying Urban Saw Timber Abundance and Quality in Southeastern Lower Michigan, U.S.

David W. MacFarlane

Abstract. There is a growing need for society to use resources efficiently, including effective use of dead and dying trees in urban areas. Harvesting saw timber from urban trees is a high-end use, but currently, much urban wood ends up in landfills or is used for wood chips or biomass fuel. To assess the general feasibility of harvesting urban wood, a regional estimate of urban saw timber quantity, quality, and availability was developed for a 13-county area in southeastern lower Michigan, U.S. Conservatively, over 16,000 m^3 (560,000 ft^3) of urban saw timber is estimated to become available each year in the study area from dead and dying trees, enough to supply the minimum annual needs of five small sawmills. The quality of wood in urban softwoods was generally low but comprised only a relatively small portion (10%) of urban wood. Wood quality of urban-grown hardwoods was comparable to that found in forests in the region, although the absolute volume was nine times less. Although there are potential concerns with harvesting urban trees for saw timber such as low availability and poor wood quality, the results of this study suggest that many of them may be unfounded.

Key Words. Saw timber; urban forestry; wood products; wood recycling.

The value of trees in urban areas has been given considerable attention, in particular for improving aesthetics, environmental quality (McPherson et al. 1999), and property values (Scott and Betters 2000). For example, recent studies have highlighted the significant contribution of urban trees to carbon sequestration (Johnson and Gerhold 2001; Nowak and Crane 2002). The wood products potential of urban trees is typically not fully realized (Bratkovich 2001; Solid Waste Association of North America 2002; Sherrill 2003), although it is sometimes among the listed values for them (Scott and Betters 2000), often because of a perceived lack of quality wood in urban trees, logistical issues associated with harvesting commercial wood that may make it economically unattractive or infeasible, and an associated lack of social infrastructure geared toward using or recycling urban wood.

The perceived lack of value for urban trees comes from legitimate concerns about foreign objects in urban trees such as nails, stone, or even signage (Sherrill 2003). However, the advent of portable sawmills with inexpensive and easy-to-change blades (e.g., Wood-Mizer®, Wood-Mizer Products Inc., Indianapolis, IN; Bratkovich 2001) as well as routine metal detection equipment on sawmill feed lines (Kerry Murphy, Weyerhauser Inc., pers. comm.) greatly reduces the impact of foreign objects in urban tree wood. Wood quality is also an important issue, however. Many urban trees are not growing under optimal conditions for saw timber production attributable to stressful site conditions and exhibit an open growth form that promotes short bole lengths and large branch knots that reduce wood quality (DeBell et al. 1994; Uusitalo and Isotalo 2005).

The main logistical problem for harvesting urban wood is that it primarily becomes available through the random death of trees and is only in abundant supply through catastrophic mortality events, e.g., the recent large-scale mortality of urban trees caused by exotic, invasive tree pests, including emerald ash borer (*Agrilus plannipennis*) (Poland and McCullough 2006) and Asian longhorned beetle (*Anoplophora glabripennis*) (Nowak et al. 2001). Other logistical concerns relate to the accessibility of urban trees for commercial harvest, because they may have to be cut into small sections to be removed safely; felling urban trees in log lengths may create excessive liability attributable to nearby hazards (but see Sherrill 2003 for suggestions on efficient and safe removal).

Recent studies by Bratkovich (2001) and Sherrill (2003) have compiled evidence suggesting that harvesting urban saw timber is not only feasible, but may also be profitable. However, no previous study has systematically estimated both the potential availability and quality of urban saw timber over a geographic region. Without specific information regarding wood quality and availability, it is difficult to generalize about the potential for harvesting saw timber from urban trees.

The goal of this study was to quantify the abundance, quality, and accessibility of urban saw timber in southeastern

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lower Michigan, U.S. using systematic inventory procedures across different urban land types and landownerships (both public and private land). Motivation for this research arose from an immediate need to address economic losses associated with an abundance of dead and dying street, park, and backyard trees killed by emerald ash borer in southeastern lower Michigan and a general desire to comprehend the potential for recovering urban saw timber.

METHODS

Study Area

The study area was comprised of urban portions of 13 counties in southeastern lower Michigan (Table 1, listed in descending order of urban land cover), which constitute the core 13 counties quarantined by the Michigan Department of Agriculture to control the spread of emerald ash borer (the beetle has since spread beyond this region). A statewide land use/land cover (LULC) classification system (IFMAP, MDNR 2003) was used to define urban areas in the 13-county region. Four of 37 IFMAP classes were deemed to represent an "urban" condition: (1) low-intensity urban; (2) high-intensity urban; (3) roads/paved (which includes areas appurtenant to roads and large paved areas such as parking lots); and (4) parks and golf courses; the first three explicitly comprise urban types in IFMAP and the last was added to represent developed greenspace appurtenant to urban land use. The remaining IFMAP classes were combined into one "nonurban" stratum that was not considered part of the potential sample space (Table 1). For this study, only roads and paved areas associated with urban areas were of interest; wood from trees associated with other roads and paved areas (e.g., roads traversing farm fields) was not of interest. The fraction of all roads and paved areas that were urban, as opposed to other roads, was approximated as proportional to the total land area that was under high-intensity and low-intensity urban land use (Table 1). Thus, the total urban land area was estimated for each county as the sum of high- and low-intensity urban land use, parks and golf courses, and "urban" roads and paved areas (Table 1).

Inventory Methods

A stratified, multistage sampling technique (Shiver and Borders 1996) was used to assess the quality and quantity of saw timber over different portions of the urban landscape. An accuracy assessment by NOAA CSCC-CAP (2003) suggested that IFMAP most accurately represented LULC types when classified map pixels (30 m × 30 m [99 ft × 99 ft]) were aggregated into larger homogeneous blocks (at least 90 m × 90 m [297 ft × 297 ft]). Thus, the grid of Michigan public survey quarter-quarter sections (QQSs) were chosen to define large (402 m × 402 m [1327 ft × 1327 ft]) primary sample units from which representative urban areas could be selected.

During the first stage of sampling, random QQSs were chosen within the 13-county area. If the randomly selected QQS was composed of a relatively homogeneous block of one of three urban types (high-intensity urban, low-intensity urban, or parks and golf courses), then it was accepted as a sample location; if not, it was rejected. The roads and paved LULC type was excepted because it never formed relatively homogeneous blocks but was a linear network that traversed portions of QQS blocks. Instead, roads and paved areas were sampled within randomly selected blocks dominated by either high-intensity or low-intensity urban areas such that only

Table 1. Urban land use composition in 13 counties in southeastern lower Michigan based on a statewide classified satellite image (IFMAP, MDNR 2003).

County	Area (ha)	Parks and golf	High-intensity urban	Low-intensity urban	Roads/paved (urban + other)	% Urban	% Nonurban
Wayne	166,482	2.24%	15.29%	13.17%	5.72% + 14.37%	36.42%	63.58%
Macomb	125,359	1.99%	8.62%	10.53%	2.13% + 9.01%	23.27%	76.73%
Oakland	234,912	1.89%	5.93%	8.72%	1.33% + 7.72%	17.87%	82.13%
Genesee	168,203	0.60%	4.06%	6.69%	0.69% + 5.75%	12.04%	87.96%
Ingham	145,169	0.54%	3.16%	3.32%	0.33% + 4.70%	7.34%	92.66%
Washtenaw	187,041	0.93%	2.14%	2.65%	0.22% + 4.38%	5.94%	94.06%
Livingston	151,581	0.55%	1.77%	2.26%	0.16% + 3.88%	4.74%	95.26%
Monroe	144,466	0.07%	2.12%	2.08%	0.20% + 4.60%	4.47%	95.53%
Jackson	187,313	0.55%	1.08%	2.31%	0.12% + 3.49%	4.05%	95.95%
St. Clair	190,407	0.22%	1.20%	2.02%	0.12% + 3.61%	3.56%	96.44%
Shiawassee	140,056	0.05%	1.18%	1.18%	0.09% + 3.90%	2.51%	97.49%
Lenawee	197,129	0.00%	0.71%	1.29%	0.07% + 3.66%	2.08%	97.92%
Lapeer	171,666	0.05%	0.40%	1.18%	0.04% + 2.40%	1.66%	98.34%
13-county area	2,209,786	0.77%	3.61%	4.44%	0.51% + 5.82%	9.32%	90.68%

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urban roads and paved areas would be sampled (as described previously).

For the second stage of sampling, field crews visited each selected QQS sample unit and systematically sampled a variable number of variable-area plots that combined to cover urban portions of the total QQS area. The field crew began from an arbitrarily determined point along the edge of a QQS (generally determined by road access) and then moved across the QQS systematically in a serpentine pattern. Permission to sample on private land was obtained in the field, or occasionally in advance; a portion of potential sample space was not sampled as a result of lack of landowner permission. Variable area rectangular plots were systematically established using one of the following three methods applied to the four different IFMAP LULC classes:

1. If the area was either high- or low-intensity urban residential or commercial, each ownership was considered a variable area plot. Lot dimensions (property boundaries within the QQS) were approximated by a rectangle and all trees inside the rectangle were part of the potential sample population (including all buildings, paved and mowed areas within the property boundaries).
2. Roads/paved areas were measured as variable area rectangles bounded by the outer edge of sidewalks, curbs, or pavement; as such, they included pavement sidewalks and mowed areas if they were between the sidewalk and the curb or pavement. Trees that were growing outside of this envelope (most typically trees that were planted between the sidewalk and a lawn or structure) were not considered as road trees/paved area trees (these trees ended up in one of the other urban stratum).
3. If the area was a park or a golf course, then beginning from an arbitrary starting point along the edge of the QQS, the field crew defined a series of plot boundary lines that were approximately equidistant between two areas of treed space (e.g., two rows of planted trees along a fairway) creating variable area rectangular plots, which included intervening areas between groups of trees or isolated trees (e.g., mowed grass).

The third stage of sampling involved selecting sample trees of all species within plots that met the common minimum size standard for saw timber trees in Michigan: 20 cm (8 in) or greater stem diameter at breast height (1.37 m [4.5 ft]) dbh. Live, dying, standing dead trees were all measured; stumps were measured at stump height (typically ≈10 to 20 cm [4 to 8 in]) aboveground level. On each tree selected, the following was recorded for estimating saw timber quantity, quality, and accessibility: species (if identifiable, e.g., on stumps and dead trees), stem diameter (at breast or stump height as above), and total tree height and total saw timber log length in the main stem to an approximately 20 cm (4 in) top diameter outside bark (DOB) (measured with a Wheeler® pentaprism, Forestry Suppliers Inc., Jackson, MS), also known as "merchantable" height (Avery and Burkhart 1994). If the main stem forked, the largest of the forks was followed to assess merchantable height; the other forks were considered part of the crown's branches.

The number of 2.4 m (8 ft) branch logs in a tree's crown with a minimum 20 cm (4 in) small end diameter DOB in the tree's crown (8 ft [2.4 m] is the standard log length on Michigan timberlands) was also tallied on any tree with large enough branches in its crown. In typical forest inventories, tree branches are not tallied and saw timber volume is estimated only for the main stem using information on merchantable height, dbh, and some geometric model of a tree's stem (e.g., a stem taper model; Zakrzewski and MacFarlane 2006). Urban (i.e., open)-grown trees have a much greater proportion of wood and larger branches in their crowns relative to forest-grown grown trees, however, so merchantable (sense Avery and Burkhart 1994) crown wood was tallied to account for this potential source of saw timber.

To assess wood quality, each tree was assigned a saw log grade using six grading classes for hardwoods (Rast et al. 1973): (0) no saw volume, (1) grade 1 saw timber, (2) grade 2 saw timber, (3) grade 3 saw timber, (4) construction grade, and (5) local use class, which aligned with tree grading classes used by the U.S.D.A. Forest Service in the national forest inventory (Miles et al. 2001). Only four grading classes were used for softwoods: (0) no saw volume, (1) grade 1 saw timber, (2) grade 2 saw timber, and (3) grade 3 saw timber, consistent with common softwood grading rules (Avery and Burkhart 1994). Crown logs were not graded as a result of lack of an objective standard for doing so.

To assess the accessibility of merchantable wood in it, each tree was classified into one of three accessibility classes representing the effort that would be involved in extracting the timber from the tree:

1. *Easily accessible* = tree could be cut into relatively long sections and could be felled with minimal risk of property damage; cut sections could be loaded readily onto a vehicle for transport.
2. *Moderately accessible* = tree could be cut into merchantable-length sections but would require additional effort to access with enhanced risk of property damage; cut sections would have to be transported a modest distance to be loaded onto a vehicle for transport (a truck could not drive up near the tree).
3. *Difficult to access* = much of the tree would have to be cut into submerchantable lengths to remove and/or trees could not be accessed without major effort (e.g., a large tree build into a deck) or a high likelihood of property damage.

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Data Analysis

Tree Wood Volume Estimation

Stem measurements were used to estimate the total merchantable saw timber round wood volume (m^3) in each sample tree from 0.15 cm (0.06 in) stump height to an approximate 20 cm (8 in) top DOB with Smalian's formula (Avery and Burkhart 1994). An individual taper model for each tree derived from its top diameter and dbh was used to account for stem taper during volume calculations (change in stem diameter over log length was extrapolated to predict stump diameter outside bark for each tree). A species-level constant bark factor model, predicting wood volume inside bark from wood volume outside bark, was used to estimate solid wood and bark volumes from total volume (Smith 1985). Exotic tree species were assigned a bark factor of a species in the same genera with an equivalent bark type. Recovered sawn lumber volume in standing trees was computed using the tree's taper model and the International ¼ in Board-foot rule for variable length logs (Freese 1973) so that recovered saw lumber could be compared with cubic round wood volume estimates (i.e., accounting for losses attributable to sawing). Crown wood board-foot volume was estimated using a model relating the basal area (BA_i, ft^2) and the number of merchantable 8 ft (26.4 m) saw logs (L_i) in the crown of a tree to its International ¼ in Board-foot rule volume (V_{Si}): $V_{Si} = 19.30\ (BA_i\ L_i)^{0.74}$ derived from felled and dissected trees on Michigan timberlands (MacFarlane, unpublished).

Scaling Up Individual Tree Estimates to the 13-County Region

Average saw timber volume per hectare (m^3 and bd ft) was estimated from the number of sample trees 20 cm (8 in) dbh or greater on a sample plot with an area a_i. The contribution of each sample tree to per hectare estimates was weighted according to its selection probability, which was proportional to the size of the variable area plot on which it occurred (Shiver and Borders 1996); the variance of sample means was also weighted in the same way. Estimates from each of the LULC classes were then combined to estimate the overall urban condition for the 13-county region using typical procedures for combining stratum in stratified sampling (Shiver and Borders 1996) with contributions of plots from each LULC weighted by the fraction of urban area they comprised (Table 1).

RESULTS

Overall, 76 urban QQSs were surveyed and 1887 stems and stumps 20 cm (8 in) or greater were measured translating into a mean density of 12.8 [±2.1 (standard error of mean) stems and stumps ha^{-1} (5.8 [±0.8] ac^{-1}) across the 13-county urban area; 89.7% were healthy, live trees, 6.3% were classed as dying, 3.7% were stumps, and 0.3% were dead, standing trees. Estimated density values for LULCs were 9.5 [±3.1], 13.7 [±3.5], 18.8 [±4.2], and 20.3 [±3.7] stems and stumps ha^{-1} for high-intensity urban, low-intensity urban, parks and golf courses, and roads and paved areas, respectively. At least 68 species (with 20 cm [8 in] or greater) representing 36 genera were found (some trees were only identified to their generic scientific name and species could not be identified for all stumps); each was assigned to a species-product class (see Appendix) based on U.S.D.A. Forest Inventory and Analysis groupings (Miles et al. 2001).

Urban Wood Volume Grade and Species-Products

The mean urban (round) wood volume across the 13-county area in tree stem sections 20 cm (8 in) or greater dbh was estimated to be 7.9 [±1.3] m^3/ha^{-1} (117.2 ± 19.9 ft^3/ac^{-1}), ≈31% of which was graded as having no saw timber value (grade 0; Table 2) as a result of major rot, defects, and other problems (see Rast et al. 1973). Approximately 56% of all graded (not including crown wood) softwood volume per acre was deemed as having no saw timber value, whereas only 35% of potentially commercial hardwood stems were graded as unfit for saw timber products (Table 2). Approximately 73% of all stems of "noncommercial" species (Table 1) were rated as unsuited for saw timber. Less than 5% of red oak (shingle oak, *Quercus imbricaria*; pin oak, *Q. palustris*; northern red oak, *Q. rubra*; black oak, *Q. velutina*), white oak (white oak, *Q. alba*; swamp white oak, *Q. bicolor*; bur oak, *Q. macrocarpa*; English oak, *Q. robur*), and black walnut (*Juglans nigra*) wood was rated as having no value, whereas a large proportion of hard maple (58%) (hedge maple, *Acer campestre*; black maple, *A. nigrum*; sugar maple, *A. saccharum*) and soft maple (42%) (boxelder, *A. negundo*; Norway maple, *A. platanoides*; red maple, *A. rubrum*; silver maple, *A. saccharinum*) wood was graded as having no saw timber value.

Approximately 60% of mean urban wood volume was saw timber grade (grades 1 through 5; Table 2) amounting to 4.7 m^3/ha^{-1} [±0.9] (67.7 [±13.3] ft^3/ac^{-1}). Mean saw timber (round) wood volume translated into 1364 bd ft per urban hectare (552 bd ft/ac^{-1}) of sawn lumber using the International ¼ in rule (a conversion ratio of 290 bd ft per cubic meter of wood [8.2 bd ft/ft^3]). Most (93%) of urban softwood saw timber volume assigned to the lowest class (grade 3). This likely was the result of the greatly increased size and density of branch knots in open-grown coniferous trees, which are reflected in softwood grading rules (DeBell et al. 1994; Uusitalo and Isotalo 2005). In general, a smaller proportion of urban hardwood saw timber volume was in higher grade classes than in lower grade classes (11% grade 1, 13% grade 2, 24% grade 3, and 48% grade 5) except for grade 4, construction grade, which comprised only 4%. The latter reflects reservations by field technicians regarding the potential

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Table 2. Mean volume (m^3/ha^{-1}) of tree stem and branch sections 20 cm (8 in) or greater in diameter in urban areas of SE lower Michigan by species-product class and wood products grade.[z]

	Main stem grade									
Spp-product class	0	1	2	3	4	5	Crown	Total volume	Total grade (1–5)	% Crown wood
Softwoods										
Spruce-fir	0.3177	—	0.0021	0.2831	—	—	—	0.6029	0.2852	0.00%
White-red pine	0.1619	—	0.0035	0.1128	—	—	0.0032	0.2812	0.1162	1.13%
Other pine	0.1218	0.0079	0.0193	0.0173	—	—	0.0012	0.1675	0.0445	0.74%
Other softwoods	0.0046	—	—	0.0389	—	—	0.0002	0.0437	0.0389	0.44%
Douglas-fir	0.0025	—	—	0.0040	—	—	—	0.0065	0.0040	0.00%
All softwoods	0.6084	0.0079	0.0249	0.4560	—	—	0.0046	1.1018	0.4887	0.42%
Hardwoods										
Soft maple	1.0385	0.0032	0.0737	0.0918	0.0069	0.8172	0.4131	2.4444	0.9928	16.90%
Poplar	0.0951	0.2366	0.1398	0.2550	0.0034	0.0390	0.0586	0.8275	0.6738	7.08%
Red oak	0.0070	0.0309	0.1040	0.2458	0.0210	0.2405	—	0.6494	0.6423	0.00%
Ash	0.0718	0.0924	0.0853	0.0203	0.0164	0.2527	0.0162	0.5550	0.4670	2.92%
Other soft hardwoods	0.1844	0.0179	—	0.1010	0.0229	0.2421	0.0505	0.6188	0.3839	8.16%
White oak	0.0130	0.0181	0.0130	0.1157	0.0352	0.1037	0.0596	0.3583	0.2856	16.65%
Hickory	0.0555	—	0.0017	0.0956	0.0371	0.0308	0.0152	0.2359	0.1652	6.44%
Walnut	0.0016	0.0248	0.0747	0.0254	—	0.0329	0.0037	0.1632	0.1578	2.26%
Other hard hardwoods	0.0810	0.0050	0.0088	0.0333	0.0101	0.0928	0.0424	0.2735	0.1501	15.52%
Hard maple	0.2082	0.0013	0.0175	0.0376	0.0184	0.0622	0.0142	0.3594	0.1370	3.96%
Basswood	0.0399	0.0142	0.0197	0.0019	—	0.0657	0.0209	0.1624	0.1016	12.88%
Birch	0.0064	—	—	—	—	0.0622	0.0024	0.0710	0.0622	3.34%
Yellow poplar	—	—	—	0.0001	—	—	—	0.0001	0.0001	0.00%
All hardwoods	1.8025	0.4444	0.5383	1.0235	0.1715	2.0418	0.6969	6.7189	4.2195	10.37%
Noncommercial	0.0633	—	0.0089	0.0056	—	0.0094	0.0116	0.0989	0.0239	11.75%
All spp-product classes	2.4742	0.4523	0.5721	1.4851	0.1715	2.0512	0.7131	7.9196	4.7322	9.00%

[z]Crown logs were not graded.
Dashes indicate no trees of this type were found during sampling.

strength and durability of urban-grown saw timber trees (i.e., these were conservatively placed in grade 5).

Approximately 89% of all urban saw timber volume (4.2 m^3/ha^{-1}) was comprised of wood from commercially recognized hardwood species, 10% from commercial softwood species (0.5 m^3/ha^{-1}), and the remaining 1% from noncommercial species (Table 2). Approximately one-fourth of all commercial hardwood saw timber was comprised of soft maple alone, and nearly two-thirds was comprised of soft maple, poplar (bigtooth aspen, *Populus grandidentata*; quaking aspen, *P. tremuloides*; cottonwood, *P. deltoides*), ash (white ash, *Fraxinus americana*; European ash, *F. excelsior*; green ash, *F. pennsylvanica*), and red oak (Table 2). Black walnut, red oak, and poplar trees had more than double the average proportion of high-grade wood (grades 1 through 3) in them, whereas the majority of saw timber from soft maples and other hard and other soft hardwood species (mostly honeylocust [*Gleditsia triacanthos*] and elm [*Ulmus americana, U. pumila]*, respectively) was rated in the lowest lumber grade classes (4 and 5; Table 2). More than three-fourths of all softwood saw timber was comprised of low-grade spruce-fir (Colorado blue spruce, *Picea pungens*; Norway spruce, *P. abies*; white spruce, *P. glauca*; white fir, *Abies concolor)* and white (*Pinus strobus*) and red pines (*P. resinosa*).

Across all species product-classes, ≈9% of mean urban wood volume (Table 2) was composed of crown logs of variable (unknown) quality amounting to 0.7 [±0.2] m^3/ha^{-1} (10.2 [±2.4] ft^3/ac^{-1}] of saw timber volume. The 0.7 m^3/ha^{-1} of crown wood translated into 176 bd ft/ha^{-1} (72 bd ft/ac^{-1}) of ungraded urban saw timber. Over half of this (0.4 m^3/ha^{-1}) was found in the crowns of soft (mostly silver) maple trees. Honeylocust, cottonwood, elm, and white oak trees also had significant amounts of saw-grade branch wood. Noncommercial species (mostly willow [*Salix* spp.] and ornamental apple [*Malus* spp.] and cherry [*Prunus* spp.] trees) had a significant proportion of their potential sawn timber in their crowns, but the absolute amounts were trivial. Urban softwoods also had insignificant amounts of saw-grade branch wood (Table 2), which was not surprising given their naturally excurrent growth form.

Regional Urban Saw Timber Abundance

The overall weighted mean urban saw timber volume for stem and crown wood in the 13-county area was estimated to

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be 5.4 [±1.7] m^3/ha^{-1}, or 1540 [±485] bd ft/ha^{-1} accounting for conversion of round wood to dimensional lumber. There was considerable variation in saw timber volume both between and within different urban LULCs. Mean graded saw timber volume was 3.0 [±1.2], 5.3 [±1.6], 7.8 [±2.1], and 7.4 [±1.7] m^3/ha^{-1}, respectively, for high-intensity urban, low-intensity urban, parks and golf courses, and roads and paved areas. Estimated crown wood saw timber volume for high-intensity urban, low-intensity urban, parks and golf courses, and roads and paved areas was 0.4 [±0.2], 0.7 [±0.3], 1.0 [±0.3], and 2.1 [±0.6] m^3/ha^{-1}, respectively. Scaled up to the 13-county region, this amounts to a total standing volume of 1.15 million m^3 of urban saw timber (≈327 million bd ft of dimensional lumber) (Table 3).

Accessibility

To successfully recover saw timber from a tree, the tree must be accessible, i.e., able to be felled, cut in sections of merchantable length, and delivered to a sawmill (in urban areas, portable sawmills can ease the latter burden). Accessibility was not equal across all urban land types (Obviously, it should be much easier to harvest wood from street and parkland trees than from around homes and offices.). Approximately 93.5% of all saw timber on parks and golf courses was considered easily accessible and less than 1% difficult to access. Almost 90% of saw timber along roads and paved areas was rated as easily accessible, although street trees were approximately four times (2.1% versus 0.5%) more likely to be rated as difficult to access than trees on parks and golf courses with the main complication being extracting wood from occasional large trees whose crowns are closely intertwined with utility wires. High-intensity urban areas posed a greater challenge for extracting saw timber from trees, although less than 4% of this saw timber was considered difficult to access. By sharp contrast, approximately half of all saw timber in low-intensity urban areas was rated as difficult to access. This reflects the close proximity of many large trees to hazards (sense Matheny and Clark 1994) such as homes or fences, in low-intensity urban areas, that would necessitate extraordinary measures to harvest trees in standard log lengths. Based on the weighted contribution of each of the four urban LULCs to total urban area (Table 1), it was estimated that ≈56% of all urban saw timber in the 13-county area was easily accessible, another 16% would require some additional measures to extract that would add additional costs (moderately accessible), and the remaining 28% difficult (for most intents and purposes considered inaccessible). Thus, of the total standing urban saw timber, ≈72% was considered accessible for extraction, amounting to 825,000 m^3 of urban saw timber (≈235 million bd ft of dimensional lumber) (Table 3).

Annual Yield

The 825,000 m^3 of urban saw timber that is accessible in the 13-county areas includes all standing trees, virtually all of which would not be harvested until the trees that contain them were dead, or at minimum dying. Thus, to calculate the availability of urban saw timber on an annual basis, it was necessary to estimate the rate at which trees would become available. However, mortality rates and removal rates could not be directly assessed from the data collected for this study (stumps, e.g., represent death events from different years and may be ground up and seeded over and thus might not be tallied at all). Instead, recent estimates by Nowak et al. (2004) describing general trends and specific tree removal and mortality rates were combined with the data presented here and used to make reasonable estimates of urban saw timber availability on an annual basis.

Nowak et al. (2004) suggested that standing trees in apparently good condition die at a rate of ≈1.4% per year. The

Table 3. Saw timber volume estimates (m^3) for urban portions of 13 counties in southeastern lower Michigan.

County	Total standing	Accessible	Annual yield
Genesee	109,358 (34,428)	78,738 (24,788)	1575 (496)
Ingham	57,5 (18,124)	41,450 (13,049)	829 (261)
Jackson	41,013 (12,912)	29,529 (9296)	591 (186)
Lapeer	15,426 (4856)	11,107 (3497)	222 (70)
Lenawee	22,094 (6956)	15,908 (5008)	318 (100)
Livingston	38,813 (12,219)	27,945 (8798)	559 (176)
Macomb	157,526 (49,591)	113,419 (35,706)	2,268 (714)
Monroe	34,835 (10,967)	25,081 (7896)	502 (158)
Oakland	226,736 (71,380)	163,250 (51,394)	3,265 (1028)
Shiawassee	18,971 (5972)	13,659 (4300)	273 (86)
St. Clair	36,594 (11,520)	26,348 (8295)	527 (166)
Washtenaw	60,017 (18,894)	43,212 (13,604)	864 (272)
Wayne	327,415 (103,075)	235,739 (74,214)	4,715 (1484)
13-county area	1,146,368 (360,894)	825,385 (259,844)	16,508 (5,197)

Standard errors in parentheses.

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latter rate was used to describe mortality in the "live" category in this study, 1.4% of the 89.7% of urban stems per acre or 1.3%. Trees with crown deterioration, equating roughly to "dying" trees in this study, had a mortality rate of ≈6.4% (Nowak et al. 2004), which equates to 0.4% more of the trees in this study. Ignoring the stumps, another 0.3% can be tallied from dead standing trees that have not yet been removed. All totaled, it can be expected that ≈2% of the accessible volume would come available annually, which translates into ≈16,500 m^3 (or ≈4.7 million bd ft) of urban saw timber per year available in the 13-county study area (Table 3).

DISCUSSION

The methods presented here allowed for a regional estimate of urban saw timber to be developed and extrapolated through urban land area estimates derived from satellite photography. Data describing urban land cover are generally widely available (e.g., the entire United States; Nowak et al. 2006); thus, these methods could be replicated almost anywhere. To the extent that average per hectare estimates derived from urban areas in southeastern lower Michigan are representative of broader regional species composition and urban tree demographic structure, these specific estimates could be further extrapolated outside of this specific region. However, the overall weighted estimates are also sensitive to the relative makeup of urban areas (e.g., a different ratio of high- versus low-intensity urban areas) such that per hectare estimates for urban LULCs would need to be reweighted accordingly.

Over 16,000 m^3 of urban saw timber is estimated to come available each year in the 13-county study area. To put this number in perspective, small modern sawmills process ≈3000 to 10,000 m^3 of wood per year annually (Pascal Kamdem, Michigan State University, pers. com.). Assuming a minimum of 3000 m^3 to remain viable, all of the potentially available wood in the 13 counties that comprise southeastern lower Michigan could support the minimum annual needs of five of these mills. The 4.7 million bd ft of lumber annually available in urban trees in this region is equivalent to the amount of wood used to build 362 average-sized homes (Falk 2002).

The quality of wood in urban softwoods was generally low based on the grading standards applied, which was not surprising given the importance of maintaining small branch knots along the main stem of (coniferous) trees to softwood quality; a condition most likely to be met when trees are forest grown (DeBell et al. 1994; Uusitalo and Isotalo 2005). However, most urban saw timber (≈90%) inventoried came from commercially viable hardwood timber species, 60% of which was considered saw-grade quality. Whereas *noncommercial* species comprise a trivial proportion of large trees, wood from exotic species did comprise a substantial proportion of urban wood (e.g., Siberian elm, Norway maple, and horsechestnut), raising potential concerns regarding their utilization (e.g., commercial kiln-drying procedures have not been developed for them). However, wood from many of these species are already commercially viable (Norway maple is considered a valuable hardwood in Germany; Jurek and Wihs 1998), and some North American vendors have been able sell wood from exotic tree species at a premium (www.urbantreesalvage.com).

One aspect of urban wood quality not addressed by this study is that of the mechanical properties of urban wood. Mackes et al. (2005) found that the modulus of rupture and modulus of elasticity were both lower in open-grown trees, primarily attributable to a greater quantity of juvenile wood, which suggests a potentially lower strength for "urban" wood. Further research would have to be done to specifically measure wood properties of urban versus forest-grown trees.

The estimates of urban saw timber presented here are likely conservative based on the definitions of "urban" area used in this study. The use of remotely sensed land use/land cover imagery to define urban areas likely underestimates the number of trees in urban areas relative to definitions based on political boundaries such as city limits or census districts (e.g., Nowak et al. 2006), which, if used, would have included wood from trees growing in forested areas within urban zones. It also likely underestimates the total amount of urban area. In a recent study, Fang et al. (2006) demonstrated that land use maps were more likely to misclassify urban areas (in Chicago) as forested than the reverse, because of the fact that many houses were beneath a canopy of trees.

Estimates of urban saw timber availability were also likely conservative based on definitions of what portion of urban wood qualified as extractable sawn wood products. Low-intensity urban areas comprised almost half of all urban area in the 13-county region (Table 1) and almost 50% of the wood in these areas was rated as difficult to access attributable to a frequent close proximity of large trees to potential hazards (e.g., homes). Sherrill (2003) proposed reasonable guidelines for safely extracting urban wood and commercial arborists to safely remove such trees all the time; thus, a larger proportion of wood from these trees may actually be accessible. Advances in sawing technology might also allow portions of some of the wood rated as grade 0 to be used for saw timber. Typical modern sawmills often dissect logs into a variety of component parts of different grades such that the visually based whole log or tree stem grading rules used here (e.g., Rast et al. 1973) may be overly conservative.

Estimates also did not include the solid wood products potential of trees smaller than 20 cm (8 in) diameter. Advances in wood technology have greatly expanded the potential for smaller trees (LeVan-Green and Livingston 2001). However, by extrapolating volume estimates for trees of different sizes measured in this study, it was estimated that trees less than 20 cm (8 in) contribute only ≈3% to the total un-

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processed volume, thus smaller diameter urban trees would likely contribute very little additional lumber.

Because most saw timber is harvested from forest-grown trees, it may be useful to compare the quality and availability of urban saw timber with that available from forests. Based on data from the U.S.D.A. Forest Inventory and Analysis program (Unit 4, Michigan, cycle 6, 2004), 5055 bd ft/ac^{-1} (12,486 bd ft/ha^{-1}) of graded saw timber is available on an average forested acre in southern lower Michigan, which is approximately nine times what was estimated for an average urban acre (552 bd ft/ac^{-1}). Ignoring softwoods in our study, which were not graded into all five U.S.D.A. Forest Services tree grades (see "Methods"), ≈59% of all forest-grown bd.ft. were in factory-grade classes (1, 2, and 3) and 41% in the construction and local use classes (grades 4 and 5), compared with 54% and 46%, respectively, for urban hardwood saw timber volume (Figure 1). Within the upper saw grades, forest- versus urban-grown hardwood saw timber volume was 14% versus 10% in grade class 1, 19% versus 12% in grade class 2, and 27.0% versus 32% for grade class 3, respectively. Thus, in an absolute sense, there are clearly many more saw timber quality trees in forested versus urban areas, but these results suggest only a small difference in wood quality relative to the large (900%) decrease in wood quantity when one harvests hardwood trees in urban versus forested areas.

Despite the potential availability of urban saw timber demonstrated here, there are still outstanding logistical problems regarding successful capitalization of it, including costs of extraction, handling, and variation in supply. One fact regarding urban trees, however, is the inevitability of their removal once they become dead or diseased, because they represent a liability (a hazard, sense Matheny and Clark 1994) and diminish aesthetic value (Scott and Betters 2000). Nowak et al. (2004) estimated that 17% of all dead standing trees in Baltimore, Maryland, were removed over a 2-year period, or ≈8.5% per year. This suggests some consistent level of urban wood will be available for harvest over time.

One caveat regarding capitalizing on urban wood made available through tree sickness and mortality is the need to properly sanitize diseased or infested trees to prevent further dissemination of the pests and pathogens that injured or killed them. A primary vector for spread of emerald ash borer, e.g., is through transportation of infested firewood to new areas (Poland and McCullough 2006). Because emerald ash borer, and most other pests and pathogens of tree stems, live and feed in the phloem, debarking trees and stripping off a small bit of the outermost wood can be a simple and highly effective treatment so long as these residual materials are properly disposed of (this has been examined for sanitizing emerald ash borer-infested ash logs in Michigan). Other methods suggested include treating infested logs with pesticides (Nzokou et al. 2006a) or preservatives (Nzokou et al. 2006b), but there

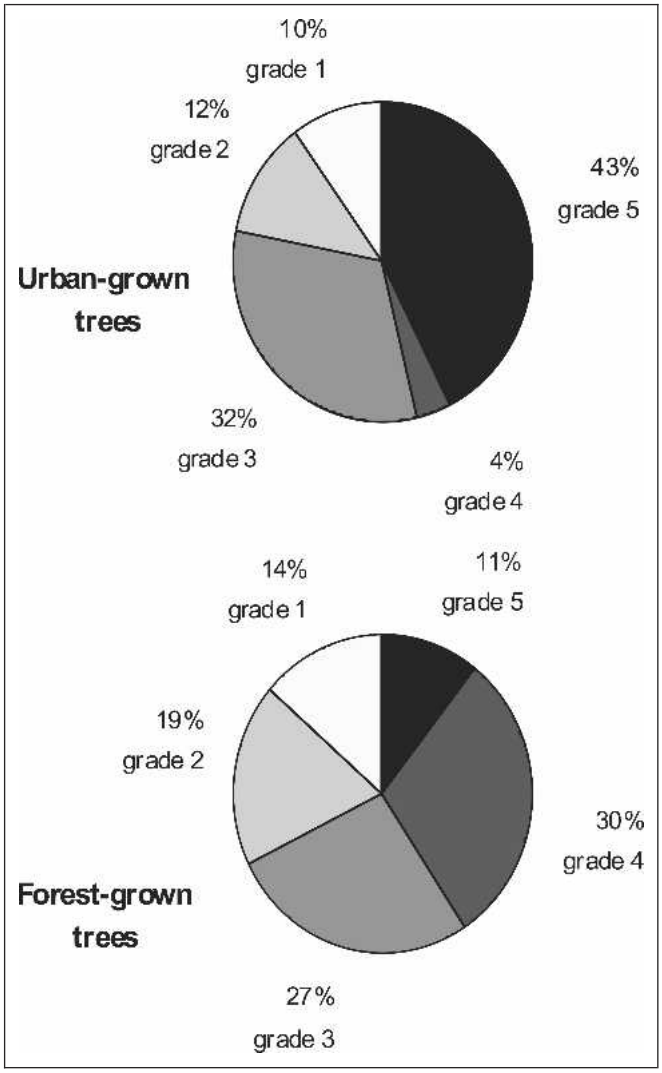

Figure 1. Comparison of saw timber quality grades (grade 1 is the highest grade) between urban- and forest-grown trees in southern lower Michigan.

are challenges to implementing such treatments at large scales.

Although it may not be realistic to expect arborists and small, private landowners to bear the logistical or financial burden of harvesting urban saw timber, clearly public entities could expand the current level of efforts. For example, the Community and Urban Forest Inventory and Management (computer) Program was recently created to help communities in California to inventory tree volume and calculate value for their urban forests (Pillsbury and Gill 2003). It has already been demonstrated on smaller scales that internal utilization of dead and dying municipal trees can offset the costs of tree removal and allow reduced infrastructural costs such as the purchase of wood for park benches and picnic pavilions (Bratkovich 2001). Training municipal foresters to grade

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trees would be an important first step toward differentiating the value of dead and dying trees. The alternative is to continue to put valuable wood products contained in urban trees to some lesser use (e.g., firewood) or, as a worst case, into a landfill (urban wood waste comprises ≈17% of all waste received at U.S. landfills; Solid Waste Association of North America 2002).

CONCLUSION

Recent economic losses associated with the destruction of urban trees by wood-boring forest pests such as the emerald ash borer highlights the well-known value associated with urban forests, not the least of which may be the valuable wood in the trees. Although there are potential concerns with harvesting urban trees for saw timber such as low availability and poor wood quality, the results of this study suggest that many of them may be unfounded. Harvesting urban wood is certainly less efficient relative to commercial logging in forests because, even if abundant, urban wood may be scattered around a large metropolitan area in smaller saleable units, greatly increasing the cost of consolidating and transporting it. However, it may not be prudent to view urban wood as an alternative to wood derived from forests. Rather, it might best be viewed as a supplementary source of wood that may help to offset the social and economic costs of urban tree removal and urban wood waste disposal to private landowners and government entities. Clearly, if southeastern lower Michigan is similar to other regions nationwide, a substantial amount of wood products volume is available from trees in urban areas.

Acknowledgments. I thank the Southeast Michigan Resource Conservation and Development Council and the Michigan Agricultural Experiment Station for providing funding and resources for this research. I also thank Sam Sherrill and Pascal Kamdem for thoughtful comments regarding this research. I thank John Kemppainen, Sean Flinn, and Hong Su An for spending many hours knocking on doors and measuring urban trees.

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Résumé. Il y a besoin croissant dans la société pour employer des ressources efficacement, et ce incluant l'utilisation des arbres morts ou mourants en milieux urbains. La récolte des billes de sciage à partir des arbres urbains constitue une utilisation ultime, mais la plupart du temps le bois se retrouve enfoui, déchiqueté en copeaux de bois ou encore est employé comme biomasse pour la production d'énergie. Pour évaluer la faisabilité générale de récolter le bois en milieu urbain, une estimation régionale de la quantité de bois de sciage, de sa qualité et de disponibilité a été faite auprès de 13 comtés dans le Sud-Est du Bas Michigan. De manière conservatrice, un volume de plus de 16000 m^3 de bois de sciage a été estimé comme étant disponible annuellement à partir des arbres morts ou mourants au sein de cette étude, ce qui s'avérait suffisant pour assurer l'approvisionnement annuel minimum de cinq petites scieries. La qualité du bois mou en milieu urbain s'avérait plutôt faible, mais ce elle ne comptait que pour 10% du volume total récoltable en milieu urbain. La qualité des bois durs en milieu urbain s'avérait quant à elle comparable à celle retrouvée dans les forêts de la région, et ce même si les volumes absolus disponibles étaient de neuf fois inférieur. Même s'il existe des inquiétudes potentielles à propos de la récolte d'arbres en milieu urbain pour des fins de sciage, telles que la faible disponibilité et la faible qualité du bois, les résultats de cette étude suggèrent que plusieurs d'entre elles pourraient s'avérer infondées.

Zusammenfassung. Es gibt eine wachsende Nachfrage nach effektiver Resourcennutzung, inklusive einer effektiven Nutzung von toten und sterbenden Bäumen in urbanen Gebieten. Die Holzernte von Stadtbäumen ist eine hochwertige Nutzung, aber viel Holz aus urbanen Regionen endet in Landverfüllungen oder wird für Hackschnitzel oder Biotreibstoff verwendet. Um die generellen Möglichkeiten von der urbanen Holzernte zu bewerten, wurde für eine Gegend mit 13 Kommunen in Lower Michigan eine regionale Schätzung der urbanen Holzquantität, -qualität und Verfügbarkeit vorgenommen. Konservativ werden jährlich über 16 Tausend m^3 in dieser Region an Totholz und absterbenden Bäumen geerntet, genug, um den jährlichen Minimalbedarf von 15 Sägemühlen zu decken. Die Holzqualität von urbanen Weichhölzern ist allgemein niedrig, aber ihr Anteil beträgt auch nur 10 % an der Gesamternte. Die Holzqualität von urban geernteten Harthölzern ist vergleichbar mit den im Wald der Region geernteten Harthölzern, obwohl das absolute Volumen nur den neunten Teil betrug. Während es möglicherweise Bedenken zur urbanen Holzernte gibt, wie geringe Verfügbarkeit oder schlechte Qualität, zeigt doch diese Studie, dass viele Bedenken unbegründet sind.

Resumen. Existe una creciente necesidad social por utilizar eficientemente los recursos, incluyendo el uso efectivo de árboles muertos y moribundos en áreas urbanas. La cosecha de madera para aserrío de los árboles urbanos está en uso, pero actualmente mucha de ella termina en rellenos o es usada para astillas o biomasa combustible. Con el propósito de evaluar la factibilidad de cosechar madera para aserrío se desarrolló una estimación regional de la cantidad, calidad y disponibilidad de madera urbana para un área del condado en el sureste del Bajo Michigan. Conservadoramente, se estima que 16 mil m^3 de madera están disponibles cada año en el área de estudio de árboles muertos y moribundos, suficiente para satisfacer las necesidades mínimas anuales de 5 aserraderos pequeños. La cantidad de madera en los bosques de madera blanda fue

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generalmente baja, pero comprendió solamente una pequeña porción (10%) de la madera urbana. La calidad de la madera de los bosques de madera dura fue comparable a la que se encuentra en los bosques nativos en la región, a pesar de que el volumen absoluto fue nueve veces menor. Con todo y que hay preocupación sobre la cosecha de los árboles urbanos para madera aserrada, tales como baja disponibilidad y pobre calidad de la madera, los resultados de este estudio sugieren que mucho de este temor es infundado.

Appendix. Study species and FIA species-product class assignments.

FIA species-product group	Common name	Latin name
Ash	Ash, European	*Fraxinus excelsior*
	Ash, green	*Fraxinus pennsylvanica*
	Ash, white	*Fraxinus Americana*
Basswood	Basswood, American	*Tilia americana*
	Linden, littleleaf	*Tilia cordata*
Birch	Birch, river	*Betula nigra*
	Birch, paper	*Betula papyrifera*
Douglas-fir	Douglas-fir	*Pseudotsuga menziesii*
Hard maple	Maple, black	*Acer nigrum*
	Maple, hedge	*Acer campestre*
	Maple, sugar	*Acer saccharum*
Hickory	Hickory, bitternut	*Carya cordiformis*
	Hickory, pignut	*Carya glabra*
	Hickory, shagbark	*Carya ovata*
	Hickory, shellbark	*Carya laciniosa*
Noncommercial	Apple	*Malus* spp.
	Ornamental cherry/plum	*Prunus* spp.
	Gingko	*Ginkgo biloba*
	Hawthorn	*Crataegus* spp.
	Mountainash, American	*Sorbus americana*
	Pear, callery	*Pyrus calleryana*
	Olive-tree, Russian	*Elaeagnus angustifolia*
	Tree-of-heaven	*Ailanthus altissima*
	Willow	*Salix* spp.
	Willow, black	*Salix nigra*
Other hard hardwoods	Chestnut	*Castanea* spp.
	Honeylocust	*Gleditsia triacanthos*
	Locust, black	*Robinia pseudoacacia*

Appendix. Study species and FIA species-product class assignments. (*continued*)

FIA species-product group	Common name	Latin name
Other pine	Pine, Austrian	*Pinus nigra*
	Pine, Scotch	*Pinus sylvestris*
Other softwoods	Baldcypress	*Taxodium distichum*
	Redcedar, eastern	*Juniperus virginiana*
	White-cedar, northern	*Thuja occidentalis*
Other soft hardwoods	Buckeye	*Aesculus* spp.
	Catalpa, northern	*Catalapa speciosa*
	Cherry, black	*Prunus serotina*
	Elm, American	*Ulmus americana*
	Elm, Siberian	*Ulmus pumila*
	Hackberry	*Celtis occidentalis*
	Horsechestnut	*Aesculus hippocastanum*
	Planetree, London	*Platanus acerifolia*
	Mulberry, red	*Morus rubra*
	Sassafras	*Sassafras albidum*
	Sweetgum	*Liquidambar styraciflua*
	Sycamore	*Platanus occidentalis*
Poplar	Aspen, bigtooth	*Populus grandidentata*
	Aspen, quaking	*Populus tremuloides*
	Cottonwood, eastern	*Populus deltoides*
Red oak	Oak, black	*Quercus velutina*
	Oak, northern red	*Quercus rubra*
	Oak, pin	*Quercus palustris*
	Oak, shingle	*Quercus imbricaria*
Soft maple	Boxelder	*Acer negundo*
	Maple, Norway	*Acer platanoides*
	Maple, red	*Acer rubrum*
	Maple, silver	*Acer saccharinum*
Spruce-fir	Fir, white	*Abies concolor*
	Spruce, Colorado blue	*Picea pungens*
	Spruce, Norway	*Picea abies*
	Spruce, white	*Picea glauca*
Walnut	Walnut, black	*Juglans nigra*
White oak	Oak, bur	*Quercus macrocarpa*
	Oak, English	*Quercus robur*
	Oak, swamp white	*Quercus bicolor*
	Oak, white	*Quercus alba*
White-red pine	Pine, eastern white	*Pinus strobus*
	Pine, red	*Pinus resinosa*
Yellow poplar	Yellow-poplar	*Liriodendron tulipifera*

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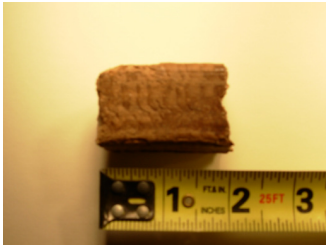
L. renewaFuel Wood Dust MSDS

Version: 1.1
August 28, 2008

MATERIAL SAFETY DATA SHEET
RENEWAFUEL

MANUFACTURER: RENEWAFUEL, LLC
1100 SUPERIOR AVE., SUITE 1500
CLEVELAND, OH 44114-2544
216-694-4855



TRADE NAME: Renewafuel (RF-MON-0701; wood-based)
SYNONYMS: Wood dust, sawdust, wood pellets
CAS. NO.: None
DESCRIPTION: Pressure-formed solid fuel product manufactured from wood particles generated by manual or mechanical cutting or abrasion process performed on wood.
Does not contain any additional binding agents.

PHYSICAL DATA

Sample No.		RF-0701	
		As Rec'd	Dried
Parameter	Units	Basis	Basis
Total Moisture (LOD)	% w/w	4.46	NA
Ash	% w/w	0.58	0.61
TX* as Cl	% w/w	0.009	0.01
Carbon	% w/w	47.07	49.27
Hydrogen (excl. moisutee)	% w/w	5.56	5.82
Hydrogen (incl. moisture)	% w/w	6.06	NA
Oxygen (excl. moisture)	% w/w	41.58	43.52
Oxygen (incl. moisture)	% w/w	45.54	NA
Nitrogen	% w/w	0.28	0.29
Sulfur	% w/w	<0.02	<0.02
Volatile Matter	% w/w	77.17	80.77
Fixed Carbon	% w/w	17.79	18.62
Higher Heating Value	BTU/lb	7,985	8,358
Boiling Point		NA	NA
Specific Gravity		NA	NA
Vapor Density		NA	NA
% Volatiles by Volume		NA	NA
Melting Point		NA	NA
Vapor Pressure		NA	NA
Solubility in H2O (% by wt.)		Insoluble	
Evaporation Rate - (Butyl =1)		NA	NA
pH		NA	NA
Appearance & Odor		Light to dark colored cube-shaped solid. Color and odor are dependent on the wood species and time since wood dust was generated.	

FIRE & EXPLOSION DATA

Flash Point ..... Not Applicable
Autoignition Temperature..... Variable (typically 400-500°F)
Explosive Limits in Air..... 40 grams/m^3 (LEL)
Extinguishing Media..... Water, CO_2, Sand
Special Fire Fighting Procedures ..... Wet down with water. Wet down wood dust to reduce likelihood of ignition or dispersion of dust into the air. Remove burned or wet fuel to open area after fire is extinguished.
Unusual Fire & Explosion Hazard ..... Strong to severe explosion hazard if wood cubes are allowed to disintegrate to wood dust and a dust "cloud" contacts an ignition source.

HEALTH EFFECTS DATA

Exposure Limit..... ACGIH TLV(R):
TWA - 5.0 mg/m^3;
STEL$_{(15\ min.)}$ - 10 mg/m^3 $_{(softwood)}$ TWA - 1.0 mg/m^3;
(certain hardwoods such as beech and oak)
OSHA PEL: TWA (see Footnote 1) - (total dust) - 15.0 mg/m^3
(respirable factor) - 5.0 mg/m^3
Skin & Eye Contact ..... Eye Irritation & Allergic Contact Dermatitis. (Wood dust can cause eye irritation. Various species of wood dust can elicit allergic contact dermatitis in sensitized individuals)
Ingestion..... Not Applicable
Skin Absorption ..... Not known to occur
Inhalation ..... May cause: nasal dryness, irritation & obstruction. Coughing, wheezing, & sneezing: sinusitis & prolonged colds have also been reported.
Chronic Effects ..... May cause: wood dust, depending on species, may cause dermatitis on prolonged repetitive contact; may cause respiratory sensitization and/or irritation. IARC classifies wood dust as a carcinogen to humans (Group 1). This classification is based primarily on IARC's evaluation of increased risk in the occurrence of adenocarcinomas of the nasal cavities and paranasal sinuses associated with exposure to wood dust. IARC did not find sufficient evidence to associate cancers of the oropharynx, hypopharynx, lung, lymphatic and hematopoietic systems, stomach, colon, or rectum with exposure to wood dust.

REACTIVITY DATA

Conditions Contributing to Instability .... Stable (under normal Conditions)
Incompatibility..... Avoid Contact with: oxidizing agents, drying oils and flame. Product may ignite at temperatures in excess of 400° F.
Hazardous Decomposition Products ..... Thermal-oxidative degradation of wood produces: irritating & toxic fumes and gases, including CO, aldehydes and organic acids.
Conditions Contributing to Polymerization ..... Not Applicable

PRECAUTIONS AND SAFE HANDLING

Eye Contact.....Avoid
Skin Contact.....Avoid: Repeated or prolonged contact with skin. Careful bathing and clean clothes are indicated after exposure.
Inhalation .....Avoid: Prolonged or repeated breathing of wood dust in air.
Oxidizing agents and drying oils .....Avoid contact
Open flame.....Avoid

GENERALLY APPLICABLE CONTROL MEASURES

Ventilation.....Provide: adequate general and local exhaust ventilation to maintain healthful working conditions.
Safety Equipment.....Wear goggles or safety glasses. Other protective equipment such as gloves and approved dust respirators may be needed depending upon dust conditions.

EMERGENCY AND FIRST AID PROCEDURES

Eyes.....Flush with water to remove dust particles. If irritation persists, get medical attention.
Skin .....Get Medical advice. If a rash or persistent irritation or dermatitis occur, get medical advice where applicable before returning to work where wood dust is present.
Inhalation .....Remove to fresh air. If persistent irritation, severe coughing, breathing difficulties occur, get medical advice before returning to work where wood dust is present.
Ingestion.....Not Applicable

SPILL/LEAK CLEAN-UP PROCEDURES

Recovery or Disposal.....Clean-up: Sweep or vacuum spills for recovery or disposal; avoid creating dust conditions. Provide good ventilation where dust conditions may occur. Place recovered wood dust in a container for proper disposal.

FOOTNOTE

Footnote 1: In AFL-CIO v. OSHA 965 F. 2d 962 (11th Cir. 1992), the court overturned OSHA's 1989 Air Contaminants Rule, including the specific PELs for wood dust that OSHA had established at that time. The 1989 PELs were: TWA - 5.0 mg/m^3; STEL (15 MIN.) - 10.0 mg/m^3 (ALL SOFT AND HARD WOODS, EXCEPT WESTERN RED CEDAR); WESTERN RED CEDAR: TWA - 2.5 mg/m^3. Wood dust is now officially regulated as an organic dust under the Particulates Not Otherwise Regulated (PNOR) or Inert or Nuisance Dust categories at PELs noted under Health Effects Information section of this MSDS. However, a number of states have incorporated provisions of the 1989 standard in their state plans.

IMPORTANT

The information and data herein are believed to be accurate and have been compiled from sources believed to be reliable. It is offered for your consideration, investigation and verification. There is no warranty of any kind, express or implied, concerning the accuracy or completeness of the information and data herein. The supplier of this form will not be liable for claims relating to any party's use of or reliance on information and data contained herein regardless of whether it is claimed that the information and data are inaccurate, incomplete or otherwise misleading.

M. RF-Wyandotte Sustainability Details

renewaFUEL
A CLIFFS NATURAL RESOURCES COMPANY

200 PUBLIC SQUARE, SUITE 3300
CLEVELAND, OHIO 44114-2315

To: File

From: James Mennell

Date: June 18, 2010

Re: Renewafuel Sustainability Data
Wyandotte Municipal Services—Wood-Based Pellets Produced in Battle Creek, Michigan

---

Energy Used to Produce Wood-Based Pelletized Fuel—33.14 kWh/ton

Renewafuel's wood-based fuel used for testing at Wyandotte was produced at a rate of 4.5 tons per hour. The equipment used to produce the pellets is rated at 250 horsepower and was operated at 80 percent of capacity. Based on electrical consumption of .7457 kWh/hp multiplied by 200 hp (250 hp * .80) energy use per hour to produce the pellets was 149.14 kWh or 33.14 kWh/ton (149.14 divided by 4.5).

CO_2 Emissions from Energy Used to Produce Wood-Based Pelletized Fuel—52.36 lbs/ton

Based on an Energy Information Administration emission factor for Michigan of 1.58 lbs CO_2/kWh, CO_2 emissions per ton of pellets produced is 52.36 lbs (1.58 * 33.14).

Transportation Fuel Use—Finished Product From Battle Creek, Michigan—1.34 Gallons/Ton

Wood-based pellets were transported from Battle Creek Michigan to Wyandotte, Michigan. Wood-based pellets were shipped with two trucks using 350 Cummins motors. The trucks average 6.5 miles per gallon. The distance from Battle Creek to Wyandotte is 116 miles. 116 miles / 6.5 = 17.8 gallons. Assuming 24 tons per truck / 17.8 = fuel use of 1.34 gallons/ton.

Transportation Fuel Use—Feedstock to Battle Creek, Michigan—1.88 Gallons/Ton

Renewafuel secured wood feedstock for the test burn from Michigan sources. Fuel costs for loading feedstock averaged .27 gallons per ton, and fuel use for transportation from

suppliers to Battle Creek averaged 1.61 gallons per ton. Total fuel for loading and transporting feedstock to Battle Creek averaged 1.88 gallons per ton.

CO_2 Emissions From Transportation Fuel Use—63 lbs/Ton (total), 36.8 lbs/Ton for Feedstock to Battle Creek and 26.2 lb/ton for Finished Product to Wyandotte

Based on an Energy Information Administration emission factor of 19.564 lbs CO_2/gallon, CO_2 emissions per ton of finished pellets transported from Battle Creek to Wyandotte are 26.2 lbs (1.34 * 19.564). CO_2 emissions per ton of feedstock transported to Battle Creek are 36.8 lbs (1.88 * 19.564). Total CO_2 from transportation of feedstock to Battle Creek and finished product from Battle Creek to Wyandotte is 63 lbs/ton.

CO_2 Emissions from Combustion of Bituminous Coal Compared to Wood Pellets

Based on an Energy Information Administration emission factor bituminous coal (currently used at Wyandotte) results in CO_2 emissions of 4,931.30 lbs/ton. Combustion of Renewafuel wood pellets, which are comprised of biogenic carbon—meaning it is part of the natural carbon balance and will not add to atmospheric concentrations of CO_2--emits no creditable CO_2 emissions under international greenhouse gas accounting methods developed by the Intergovernmental Panel on Climate Change.

Carbon Balance of Renewafuel Wood-Based Fuel Compared to Bituminous Coal—Coal Emits More than 40 times More CO_2 than Renewafuel Wood-Based Fuel

CO_2 Emitting Activity	**Renewafuel Wood-Based Fuel**	**Bituminous Coal**
Mining	0	?
Methane Releases	0	?
Processing	52 lbs/ton	?
Transportation	63 lbs/ton	?
Use as Fuel at Wyandotte	0/ton	4,931 lbs/ton
TOTAL	115 lbs/ton	4,931 lbs/ton (+ mining, methane releases, processing and transportation)

Even without considering the CO_2 emissions from mining, methane releases, processing and transporting coal to Wyandotte, CO_2 emissions from use of coal are roughly 40 times higher than use of Renewafuel's wood-based fuel (even when considering all emissions from processing and transportation of the wood-based fuel).

Energy Equivalent CO_2 Emission Reductions of renewaFUEL Compared to Bituminous Coal—1.58 tons of CO_2/Ton of renewaFUEL

Assuming and average heating value of 8,000 Btu/lb for renewaFUEL and 12,500 Btu/lb for bituminous coal, a ton of renewaFUEL has 64% of the energy value of a ton of

bituminous coal. Multiplying the EIA emission factor for bituminous coal of CO_2 emissions of 4,931.30 lbs/ton by .64 equals 3,156 lbs of CO_2 (1.58 tons) from such coal on an energy-equivalent basis to one ton of renewaFUEL.

Use of 30,000 Tons of renewaFUEL in Place of Bituminous Coal Would Reduce Creditable CO_2 Emissions By the Equivalent of the Annual Use of 8,000 Cars

Assuming an offset of 1.58 tons of CO_2 per ton of renewaFUEL used in place of bituminous coal, and use of 30,000 tons of renewaFUEL, would result in reductions of 47,400 tons of CO_2. A typical car emits 0.916 lbs of CO_2 per mile. Assuming average annual use of 12,500 miles per year, a typical car would emit 11,450 lbs (5.73 tons) of CO_2 per year. Dividing annual creditable CO_2 reductions of 47,400 by 5.73 indicates use of 30,000 tons of renewaFUEL would result in creditable CO_2 reductions equivalent to the annual use of 8,272 cars.

N. Robert Froese Traverse City Presentation

Traverse City Biomass Fuels Assessment

Robert Froese, PhD, RPF
Associate Professor of
Forest Resources and Environmental Science

with contributions from

Stacie Holmes, Nan Davis
and Trevor Roberts

Traverse City Light & Power Information Session
21 January 2010 at Traverse City, MI

Michigan Tech
Michigan Technological University

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Context for this Study

- TCL&P is exploring opportunities for biomass-fueled Combined Heat and Power
- One or more 10 MW plants, total up to 40 MW
- Consider a range of fuels, including forestry residuals, energy crops and wood by barge
- Information needed on fuel properties, availability within a feasible procurement range, and expected biomass cost

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Five Biomass Fuels were Evaluated

1. Cherry Pits

These are residues from tart cherry production on orchards nearby to Traverse City

2. Mill Wastes

Bark, slabs, sawdust and planer shavings that are residues from primary forest processing facilities

http://i.pbase.com/v3/29/593629/1/50330819.Haulingchipbargeout.jpg

3. Chips by Barge

TCL&P could accept chips from remote locations delivered at an existing dock

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Five Biomass Fuels were Evaluated

4. Forestry Residuals

Tops, branches, rough and defective logs and un-merchantable trees that are residual material left over after conventional forestry operations

Could include intermediate treatments like thinning or salvage

5. Dedicated Biomass Energy Crops

Hybrid poplar trees, shrub willows, or perennial grasses like switchgrass grown using an agricultural model for dedicated use as biomass fuels

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Fuel Properties and Annual Requirements

How much biomass is required to support a 1 MW generation capacity? For this we assume 30% thermal efficiency and 90% capacity factor.

Feedstock[1]	HHV (Btu/lb)	Typical Moisture Content (wet basis)	GHV-AF[2] (Btu/lb)	Feedstock Requirement (tons/year)
Native Forest Sources				
Hardwood	8,493	45%	4,671	10,128
Softwood	9,009	45%	4,955	9,548
Dedicated Energy Crops in Plantations				
Switchgrass	7,458	11.2%	6,623	7,144
Poplar	8,073	45%	4,440	10,655
Willow	8,389	55%	3,775	12,532
Specialty Bioenergy Sources				
Cherry Pits	9,523	11%	8,476	5,582

[1]Trees as whole tree chips, switchgrass as dry bales and cherry pits as washed, dry bulk
[2]Gross Heating Value – As Fired (GHV-AF) is HHV associated with non-water fraction

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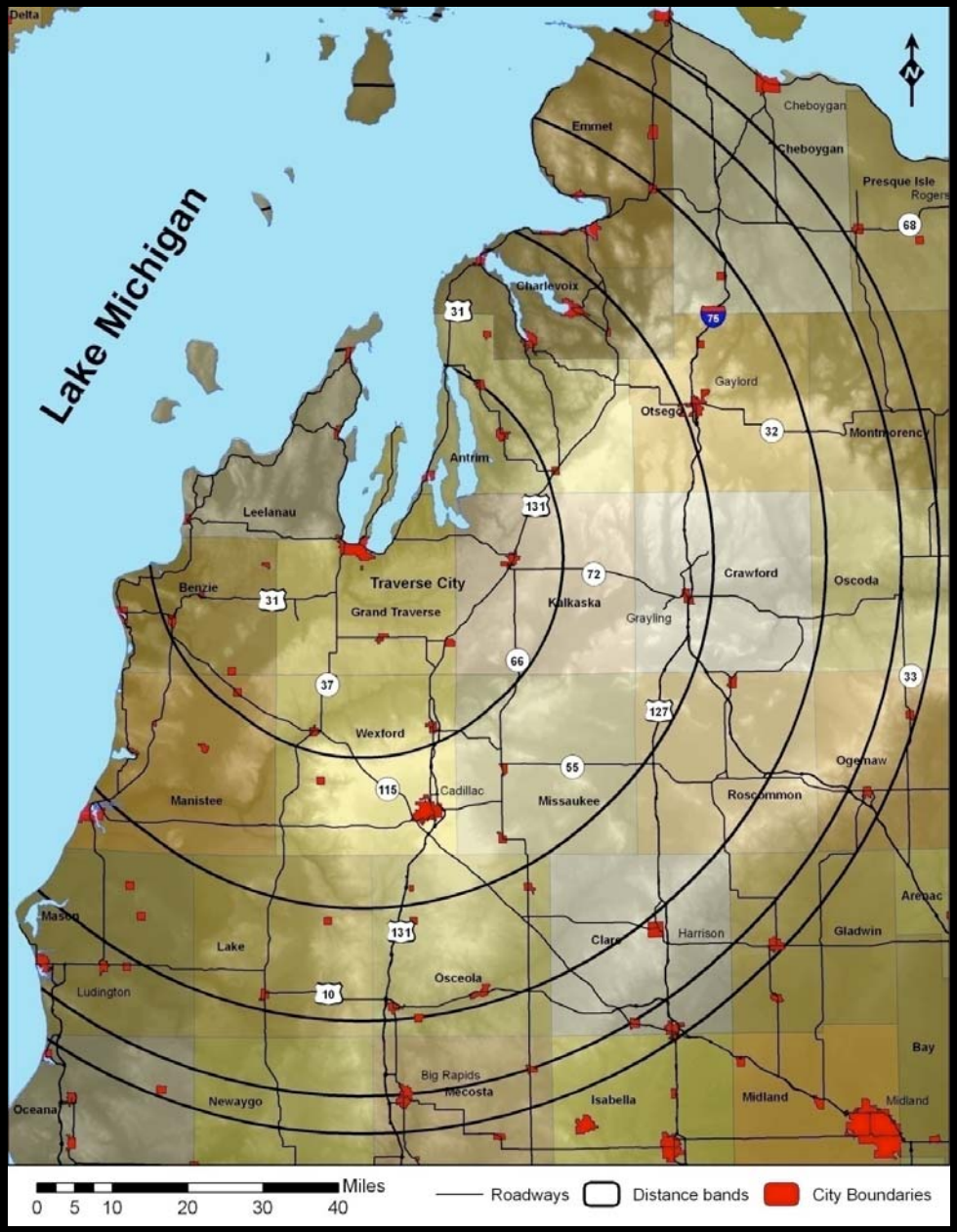
Scope - Geography

We established a reference "bioshed" with a radius of 75 miles from Traverse City

The bioshed is divided into bands to impose some spatial context for subsequent analyses.

Bands are progressively thinner as they are further from Traverse City. This means each band is roughly equal in area.



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Land Cover

Within 75 miles of Traverse City

Land Use	mi^2	Fraction
All	11,200	100%
Urban	300	3%
Lakes & Rivers	500	4%
Agriculture	1,300	11%
Marginal	2,000	17%
Forests	7,100	63%

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http://www.shorelinefruit.com/vertical-integration.html

Cherry Pits

- Michigan tart cherry production is about 75% of the National Total
- About 250 Million lb per year of raw cherries
- Pits are sold by producers and make excellent biomass fuel
  - Superior HHV
  - Low moisture content
- Price reflects value for specialty markets
- $167 per ton is about five times greater than wood chips

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http://i.pbase.com/v3/29/593629/1/50330819.Haulingchipbargeout.jpg

Wood Chips by Barge

- Michigan has 38 deep-water ports, 15 of which are on Lake Michigan
- Barge transportation is very efficient
  - Fuel efficiency is 5 times greater than rail and 10 times greater than truck
- Barge loads are large; typical barge displaces 3,400 tons
- Barge movement could be seasonal
- Little chip movement at present

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Mill Wastes are Already Utilized

Mill Wastes

1. USDA Timber Products Output

- Mill survey
- Estimates of removals and residues estimated backwards

Current Disposition	Tons by distance band (miles)					
	0-25	25-45	45-60	60-70	70-75	**0-75**
Used	131,907	261,299	55,265	90,402	149,220	632,828
Unused	0	1,956	0	0	0	1,956
Total	131,907	263,255	55,265	90,402	149,220	690,049

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Retired Lands total over 640,000 acres

Mill Wastes

1. USDA Timber Products Output

- Mill survey
- Estimates of removals and residues estimated backwards

Land Use / Land Cover

1. Michigan IFMAP (Integrated Forest Monitoring Assessment and Prescription)

- Parcels over 5 acres

Cover Type	Acres by distance band (miles)					
	0-25	25-45	45-60	60-70	70-75	**0-75**
Forage/Untilled	112,000	154,000	109,000	106,000	94,000	574,000
Herbaceous Openland	119,000	135,000	126,000	80,000	42,000	502,000
Upland Shrub	17,000	24,000	24,000	41,000	38,000	144,000
Total	248,000	313,000	258,000	227,000	173,000	1,221,000

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Forestry Residuals exceed 700,000 tons/year

Forest Consumption

1. USDA Timber Products Output

- Mill survey
- Estimates of removals and residues estimated backwards

Land Use / Land Cover

1. Michigan IFMAP (Integrated Forest Monitoring Assessment and Prescription)

- Parcels over 5 acres

Forest Inventory/Potential

1. USDA Forest Inventory and Analysis

- EVALIDator
- 2005-2007 panel
- Timberland

Source	Tons by distance band (miles)					
	0-25	25-45	45-60	60-70	70-75	**0-75**
Tops and Limbs	47,000	60,000	94,000	104,000	41,000	346,000
Un-merchantable	20,000	263,000	29,000	40,000	11,000	364,000
Total	67,000	323,000	123,000	144,000	52,000	709,000

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Forest have large renewable energy potential

Current rate of harvest of forest resources may be estimated very accurately using inventory data collected by the USDA Forest Service

Harvest is presently about 30% of growth. In other words, 70% of growth is accumulating as new inventory, year after year.

Harvest rate could be doubled and still be less than the sustainable rate. Associated residues would be substantial.

Annual Change	Million ft^3	Million tons[1]
Net Forest Growth	178	4.8
Harvest Removals	79	2.2
Mortality	47	1.3
Gross Forest Production	303	8.3
G:R	3.3	
MW		510
MW from Forest Residues		75

Source: FIA 2005-07 for annual removal of growing stock from timberland

[1]Using 30 lb/ft^3 dry biomass and 45% MC

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Dedicated Biomass Energy Crops

1. Shrub Willow

- High-density plantations using clonal cuttings on cultivated lands
- Cut every 3 years for 7-8 cycles
- Most expensive option

2. Hybrid Poplar

- Low-density plantations using clonal cuttings; cultivation optional
- Harvested on a 10-year rotation
- Commercial experience elsewhere in the Upper Midwest

3. Switchgrass

- Native warm-season grass
- Annual harvest after fall frost
- Reaches full yield in 2-4 years
- Least expensive option

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Feasible Availability Scenario

1. Existing Timber Harvest

Associated with existing harvest of logs are about 700,000 green tons/year of forestry residuals, after deducting a retention requirement for sustainability. Some of these residues are collected and used already. About 40% might be available at Traverse City.

2. New Sustainable Timber Harvest

At present, forest harvest is only 30% of forest growth and a very large potential exists for increased sustainable timber harvest. The Michigan Climate Action Council scenario assumed some new harvest could be diverted to bioenergy. If the current harvest rate were increased by 20% (i.e., from 30% of growth to 36% of growth), then about 240,000 green tons/year of low-grade logs and residuals might be available at Traverse City.

3. Dedicated Energy Crops from Retired Farmland

There are about 640,000 acres of apparently idle, retired farmlands within 75-miles of Traverse City. If TCL&P could contract for energy crop production on 20% of these lands, all of the biomass under these contracts (about 5.5 green tons/acre/year) might be available at Traverse City.

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Feasible Availability Scenario

Source	Gross Available	TCL&P Fraction	Green tons/year	Del. Cost (per ton)	Potential Electricity
Existing Timber Harvest					
Forestry Residuals	700,000	40%	280,000	$22	29 MW
New Sustainable Timber Harvest					
Low Grade Pulp	440,000	36%	158,400	$30	17 MW
Associated Residuals	140,000	60%	84,000	$22	9 MW
New Dedicated Biomass Plantations					
Energy Crops	700,000	100%	700,000	$40	70 MW
Totals	1,980,000		1,222,400		**125 MW**

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O. Sawmill Operations Serving Southeastern Michigan

Southeast Michigan Resource Conservation & Development Council

7203 Jackson Road Ann Arbor MI 48103-9506
Phone: (734) 761-6722 X 105 Fax: (734) 662-1686
Web Site: www.semircd.org

Serving Lenawee, Macomb, Monroe, Oakland, St. Clair, Washtenaw and Wayne Counties

Small and Portable Sawmill Operations Serving Southeastern Michigan

Ace Sawmill
Portable sawmill
17416 Savage Rd
Belleville, MI 48111
Ph: (734) 635-3333
E-mail: acesawmill@yahoo.com

Blue Ox Mill Works
Portable sawmill
Richard Russo
8673 W. Iosco
Fowlerville, MI 48836
Ph: (517) 223-7268

Boston Lumber
Ray Peltier
5903 State Road
Fort Gratiot, MI 48059
Ph: (810) 650-1901
E-mail: deerpelt@yahoo.com

Dan Erickson
Portable sawmill
1960 Miller Ave.
Ann Arbor, MI 48103
Ph: (734) 668-0885
Fx: (734) 647-2767

Don Brown
Portable sawmill
504 Diamond Rd.
Mason, MI 48854-8604
Ph: (517) 676-4487

Freier Forestry
P.O. Box 130710
Ann Arbor, MI 48113
Ph: (734) 320-2770, (734) 323-0027
E-mail: Freierforestry@gmail.com
http://www.freierforestryllc.com/

Gary Flint
Custom sawmill, blade sharpening
11205 Orban Road
Grass Lake, MI 49240-9809
Ph: (517) 522-3337

G&D Lumber
Portable sawmill
12860 S. Hillsdale Rd.
Camden, MI 49232
Ph: (517) 254-4463
Approx 100 Mile radius

J&E Services
John Zempke
Portable sawmill
P.O. Box 834
Lakeland, MI 48143
Ph: (810) 231-9389

J&W Tree Artisans
Tree removal & milling services
Wayne Nemeth
54445 Bates
Chesterfield Twp., MI 48051
Ph: (586)749-8672

John Haling
Portable sawmill, Kiln drying
6559 Nollar Rd.
Whitmore Lake, MI 48189
Ph: (734) 741-9499
Fx: (734) 741-9498
http://www.sawmilljohn.com/

Joseph Zalac
Portable sawmill
5125 Whitlow Ct.
Commerce Township, MI 48382
Ph: (248) 363-6521
Hobbyist

Hickory & Oak Sawmilling
Portable Sawmill, Kiln Drying
Steve Van Osdol
90930 52nd St.
Decatur, MI 49045
Ph: (269) 423-8178

Kevin Bingham
Detroit, MI
Ph: (313) 319-0583

Krupa's Custom Cutting
Sawmill owner, custom cutting, kiln
7607 South Huron River Drive
South Rockwood, MI 48179
Ph: (734) 379-3120
E-mail: krupam-l@comcast.net
http://www.krupascustomcutting.com

Last Chance Logs to Lumber
Portable sawmill
Chris Last
9971 Cardwell
Livonia, MI 48150
Ph: (734) 261-0441
Cell: (734) 564-4705
E-mail: clast@sbcglobal.net

Log 2 Lumber
Chuck Lobaito
Farmington Hills, MI
Ph: (248) 330-9033
E-mail: log2lumber@gmail.com
http://log2lumber.googlepages.com/

Logs to Lumber and Beyond
Richard Mills
Flat Rock, MI 48134
Ph: (734) 231-1210
richard@logstolumberandbeyond.com
http://www.logstolumberandbeyond.com/

Looking North Wood Products
Steve & Dawn Wilson operators
901 W State Street
St. Johns, MI 48879
Ph: (989) 224-6725
Cell: (989)-640-1505
lookingnorth@voyager.net

MDJZ Custom Cutting
Portable sawmill
Steve Mixter
7180 Pounds Ct.
Howell, MI 48855
Ph: (517) 546-6558

The Southeast Michigan RC&D Council is an equal opportunity provider and employer.
Inclusion on this list does not imply endorsement of any specific businesses and does not guarantee that listings are current.
Thanks to the Washtenaw Conservation District for providing much of the information on this list.

Meinert's Mill
Jim Meinert
7431 Lulu Rd
Petersburg, MI
Ph: (734) 279-2306

Metro Portable Sawmill
Portable Sawmill, Kiln Drying
Mike Carter
20241 Coryell Dr.
Beverly Hills, MI 48025
Ph: (248) 563-3881

Mobile Custom Sawing
Robert Dewitt
10498 Ostrander Rd.
Maybee, MI 48159
Ph: (734) 604-3604
Fx: (734) 587-3222
Also sells lumber

Pete Klink
Forestry Consultant, Kiln Drying
P.O. Box 521
Coldwater, MI 49036
Ph: (517) 238-4048

Quinn Mobile Saw Works LLC
Martin Quinn
38321 Chartier
Harrison Twp., MI 48045
Ph: (231) 557-7271
E-mail: mquinnrcs@wideopenwest.com
http://q-saw.com/

Raven Farm
7535 Clark Rd.
Bath, MI 48808
Ph: (517) 641-6189
Email: kelvinpot@yahoo.com
http://www.ravenfarm.com/

Rusty 4 Farms
Portable sawmill, Kiln Drying, Firewood
27190 L Drive North
Albion, MI 49224
Ph: (517) 629-9218
Cell: (231) 206-4381

Sawing Logz LLC
Portable sawmill, Firewood
Jeff Shelby
28634 Milton Ave.
Warren, MI 48092
Ph: (586) 883-5649

Sawmill Express
Portable sawmill
Manchester, MI
Ph: (734) 428-7975
Mike Weber - Ph: (734) 368-5914
Dave Kirk - Ph: (734) 216-6061

Scotty's Custom Sawing and Millwork
Portable sawmill, millwork, Firewood
Scott Tupacz
Belleville, MI
Ph: (734) 461-2133
Fx: (734) 787-8295

Tervol Wood Products
Portable sawmill, Kiln drying
11800 N. Adams Rd.
North Adams, MI 49262
Ph: (517) 287-5745

Pallet and Container Corp. of America
Portable sawmill, Pallet lumber buyer
Todd Burtscher
901 Buckingham St.
Toledo, Oh 43607
Ph: (419) 255-1256 - Shop
Fx: (419) 255-1257 Fax
Cell: (419) 344-3920 - best # to use
E-mail: pcca@bex.net

Ullmann Urban Sawmill
Lee Ullmann
Dexter, MI
Ph: (734)253-2585
Lon Ullmann
Troy, MI
Ph: (248)670-6875
http://uusaw.com/

Urbanwood.org
Sawmill services and online store
Cooperative network of many local mills
Retail sales at:
Recycle Ann Arbor's ReUse Center
2420 South Industrial Hwy.
Ann Arbor, MI
Ph: (734) 222-7880
http://urbanwood.org/

Variety Farms Sawmill
Portable mill, "Buyer of quality sawlogs"
Robert Bullock
11585 Dunham Rd.
Hartland, MI 48353
Ph: (810) 623-0041

Walton's Portable Sawmill
Portable Sawmill, Kiln Drying
Eric Walton
863 Hazelwood
Jackson, MI 49203
Ph: (517) 795-7815

You can also find more wood products businesses online at the

MI Department of Natural Resources' Wood Products Directory:
http://www.michigandnr.com/wood/.

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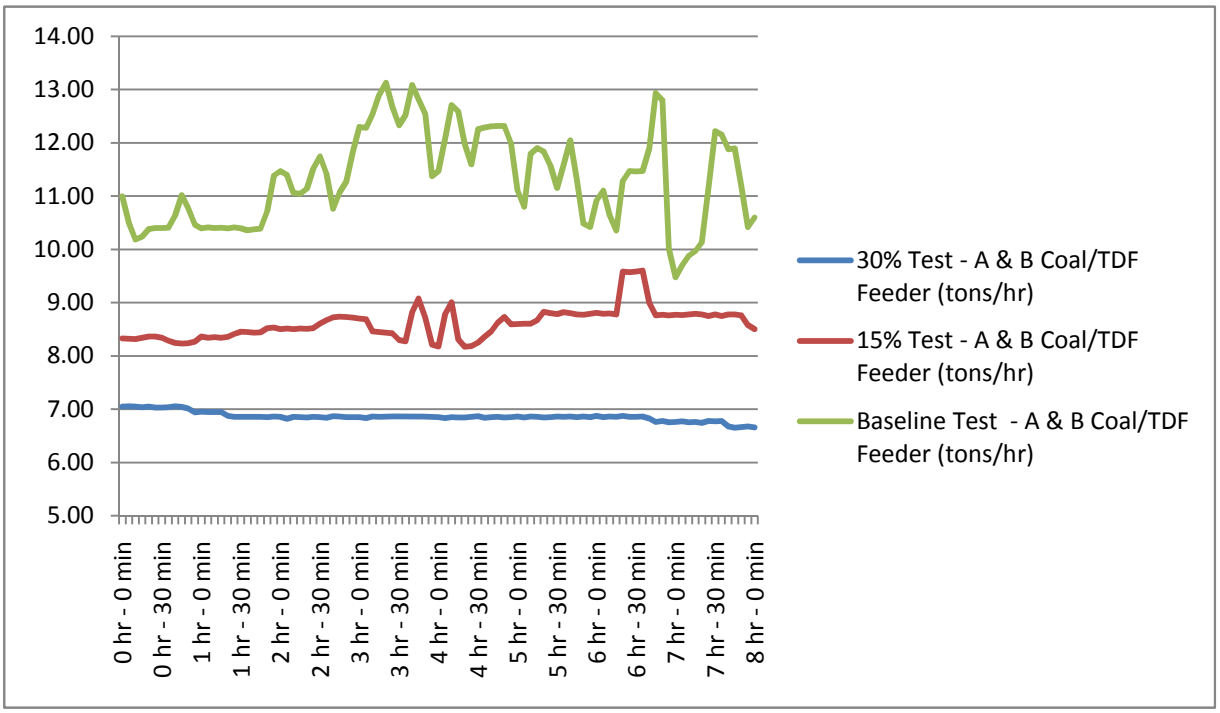
P. Test Burn PI and CEMS Data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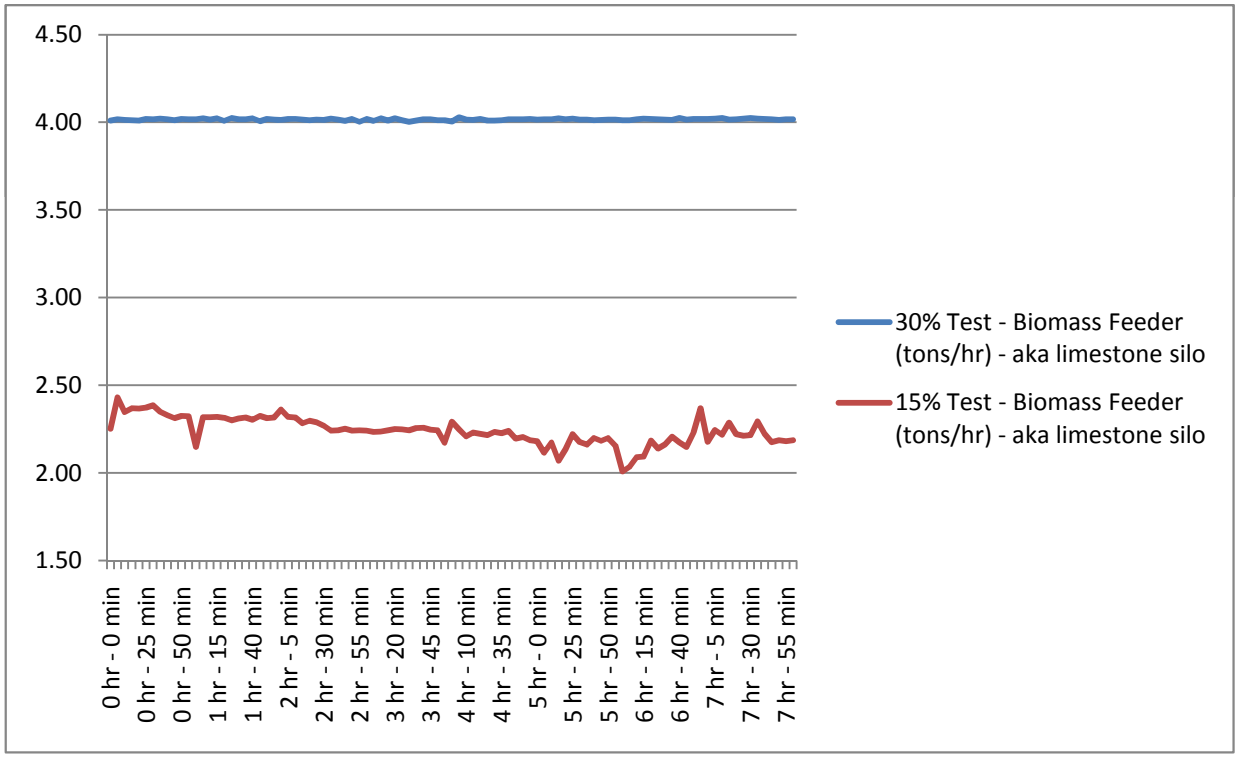
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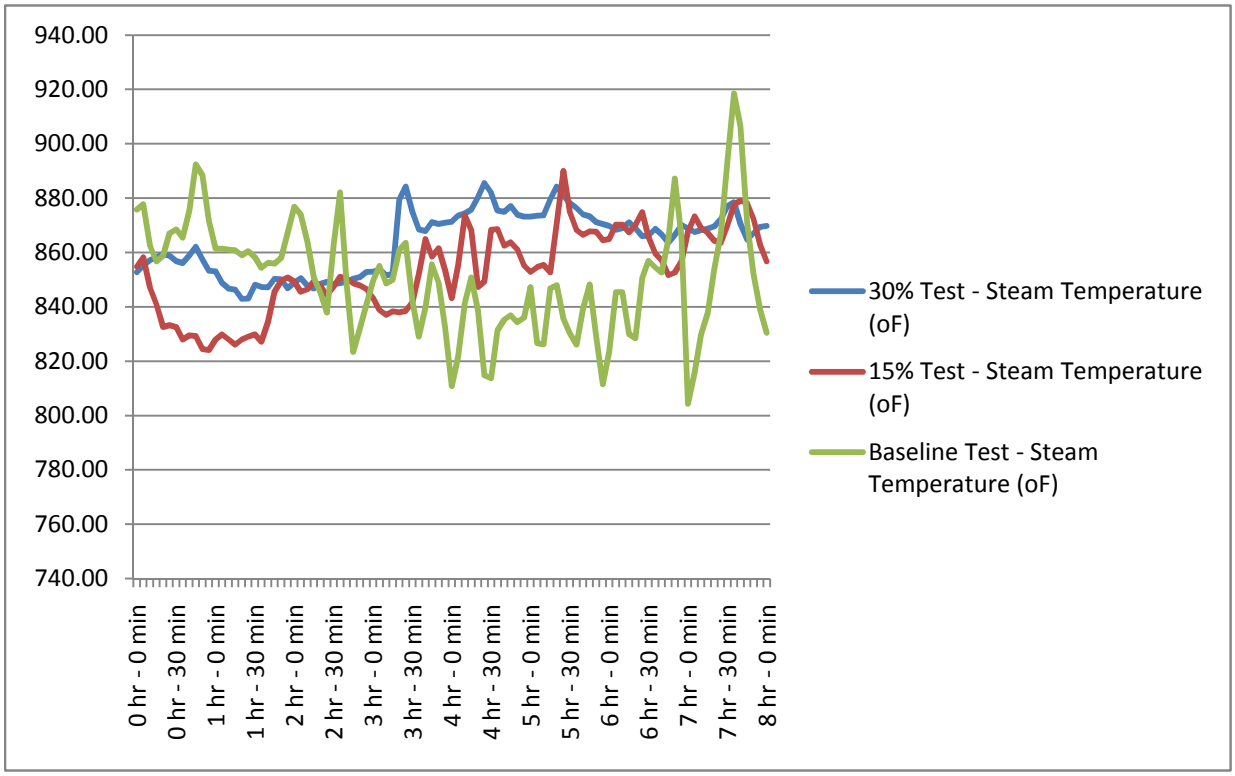
15% Test - Biomass Feeder (tons/hr) - aka limestone silo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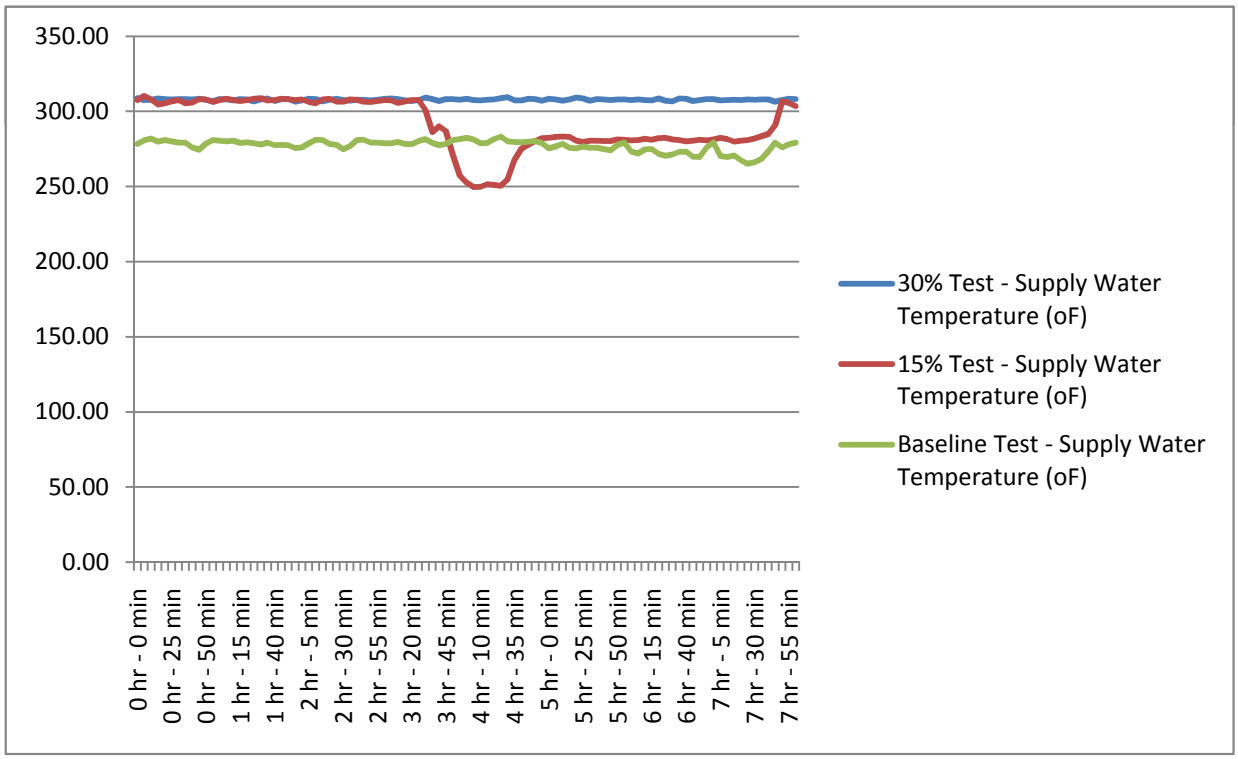
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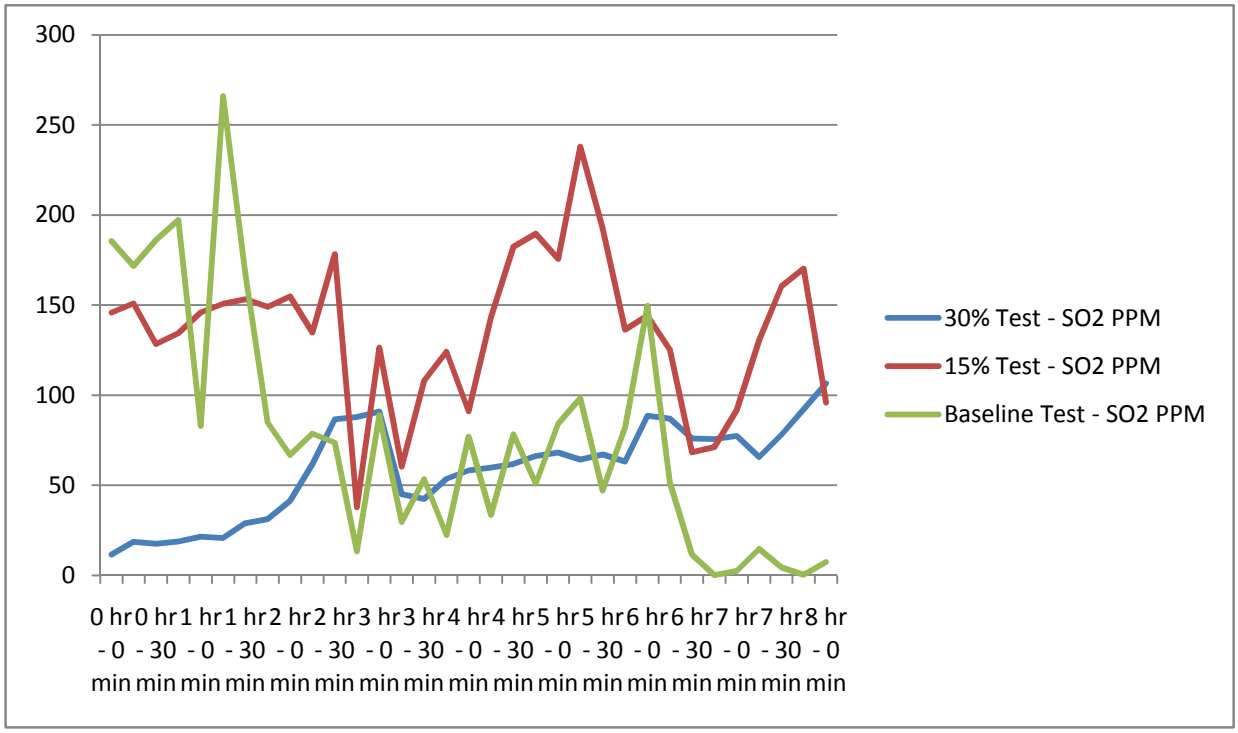
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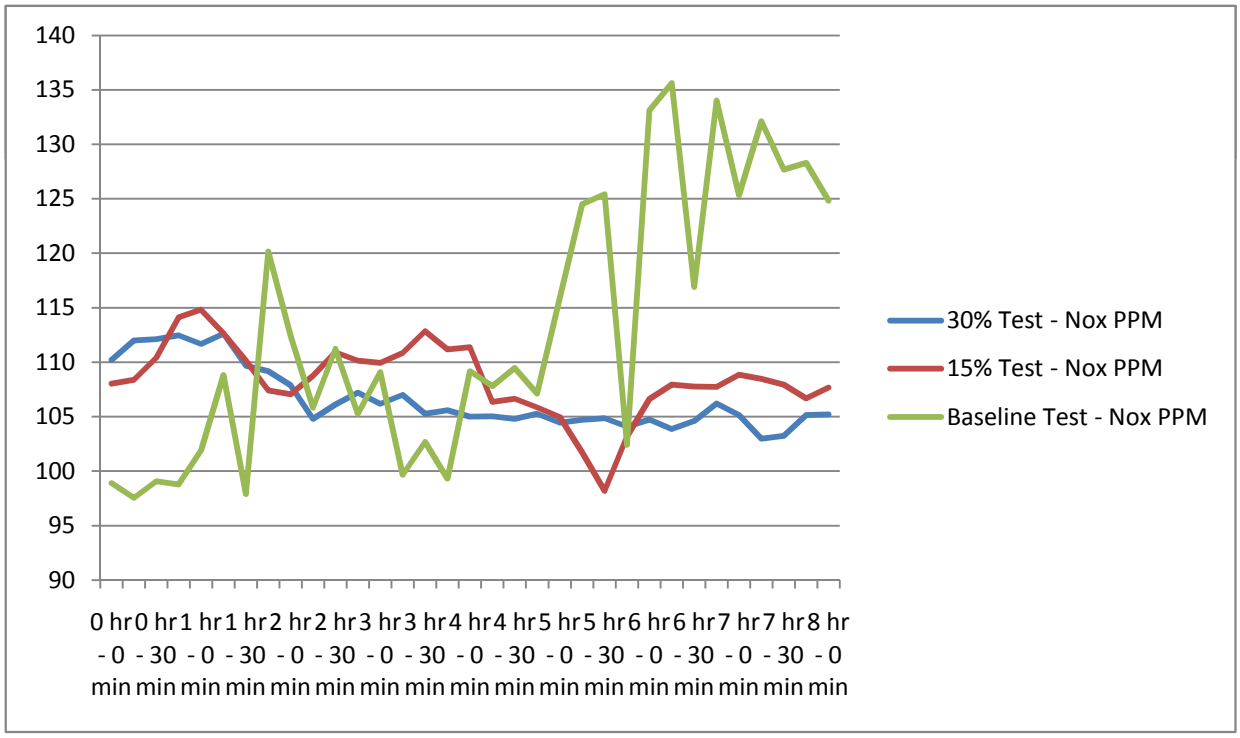
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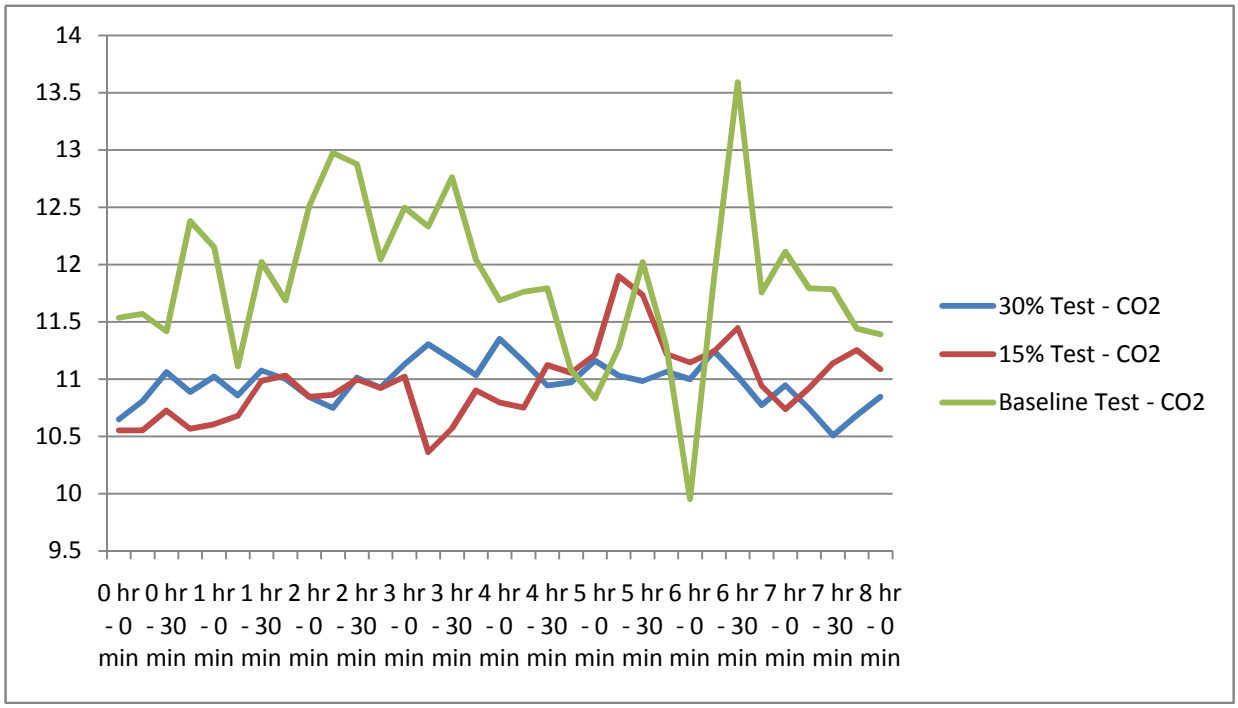
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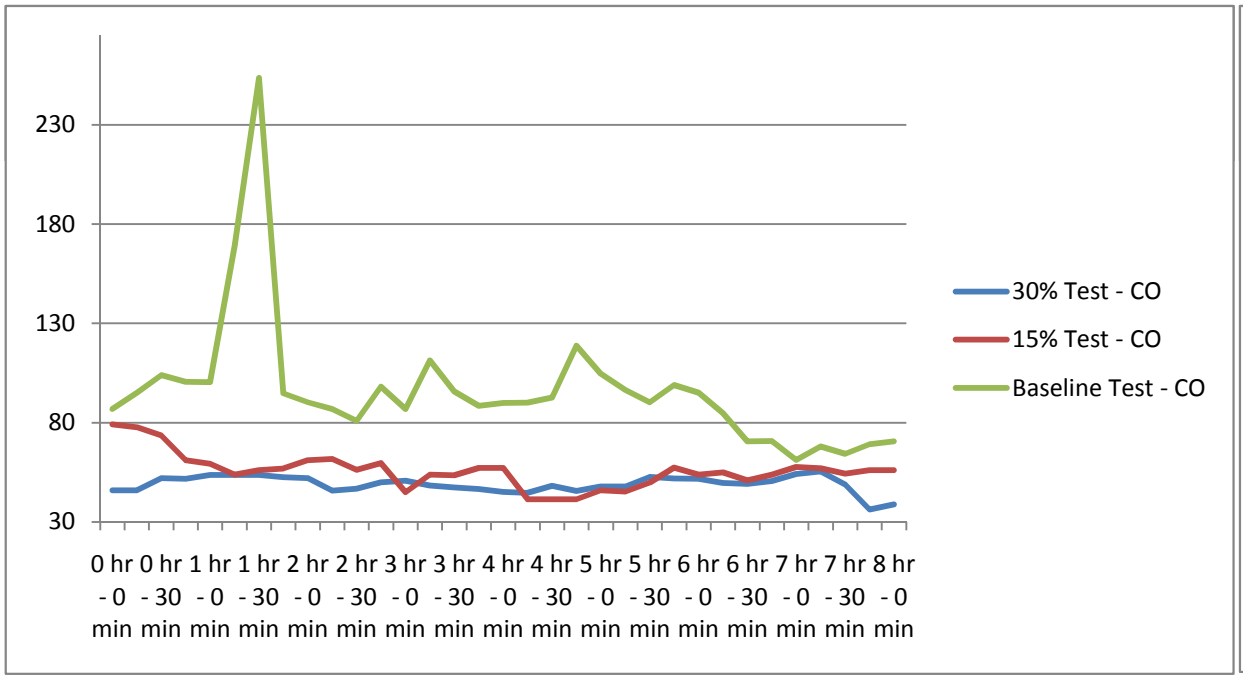
0 hr - 0 min
0 hr - 30 min
1 hr - 0 min
1 hr - 30 min
2 hr - 0 min
2 hr - 30 min
3 hr - 0 min
3 hr - 30 min
4 hr - 0 min
4 hr - 30 min
5 hr - 0 min
5 hr - 30 min
6 hr - 0 min
6 hr - 30 min
7 hr - 0 min
7 hr - 30 min
8 hr - 0 min
30% Test - CO2
15% Test - CO2
Baseline Test - CO2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180
130
80
30
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0 hr - 30 min
1 hr - 0 min
1 hr - 30 min
2 hr - 0 min
2 hr - 30 min
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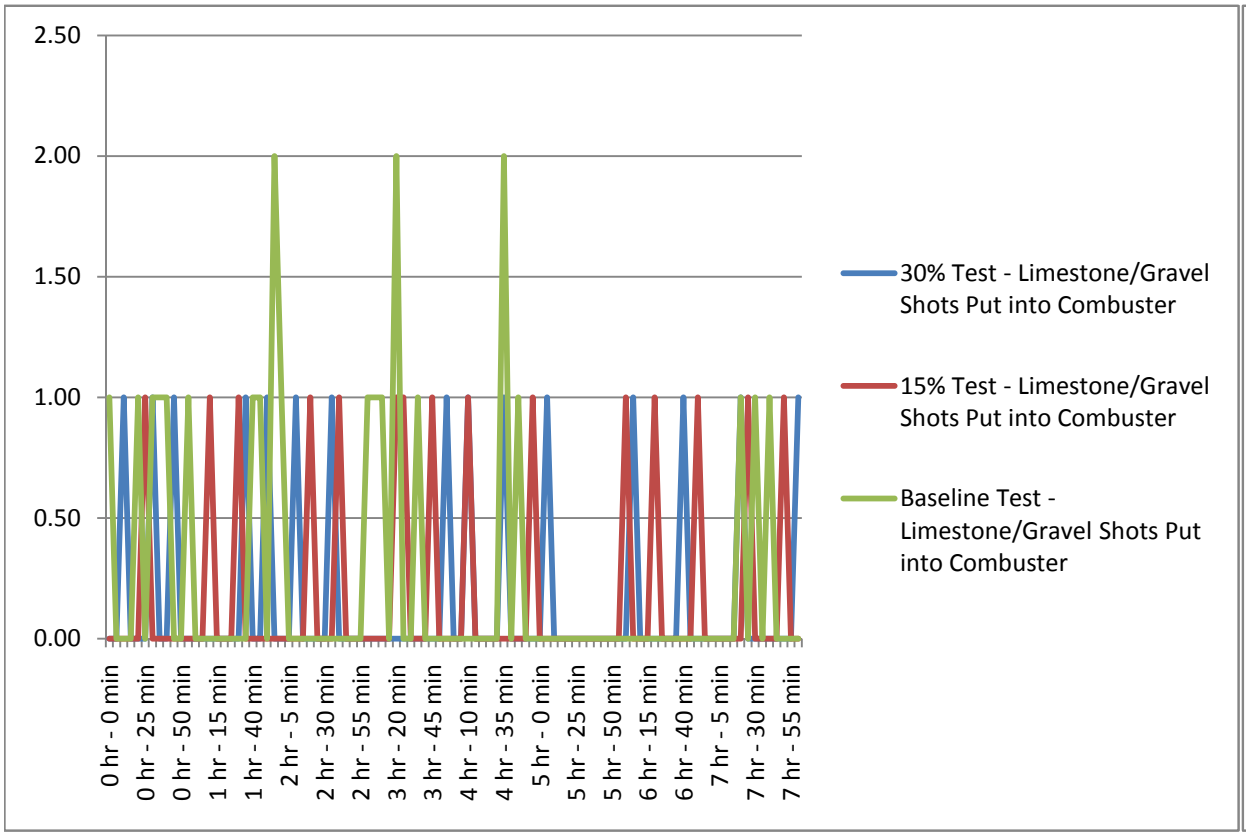
3 hr - 30 min
4 hr - 0 min
4 hr - 30 min
5 hr - 0 min
5 hr - 30 min
6 hr - 0 min
6 hr - 30 min
7 hr - 0 min
7 hr - 30 min
8 hr - 0 min
30% Test - CO
15% Test - CO
Baseline Test - CO


2.50
2.00
1.50
1.00
0.50
0.00
0 hr - 0 min
0 hr - 25 min
0 hr - 50 min
1 hr - 15 min
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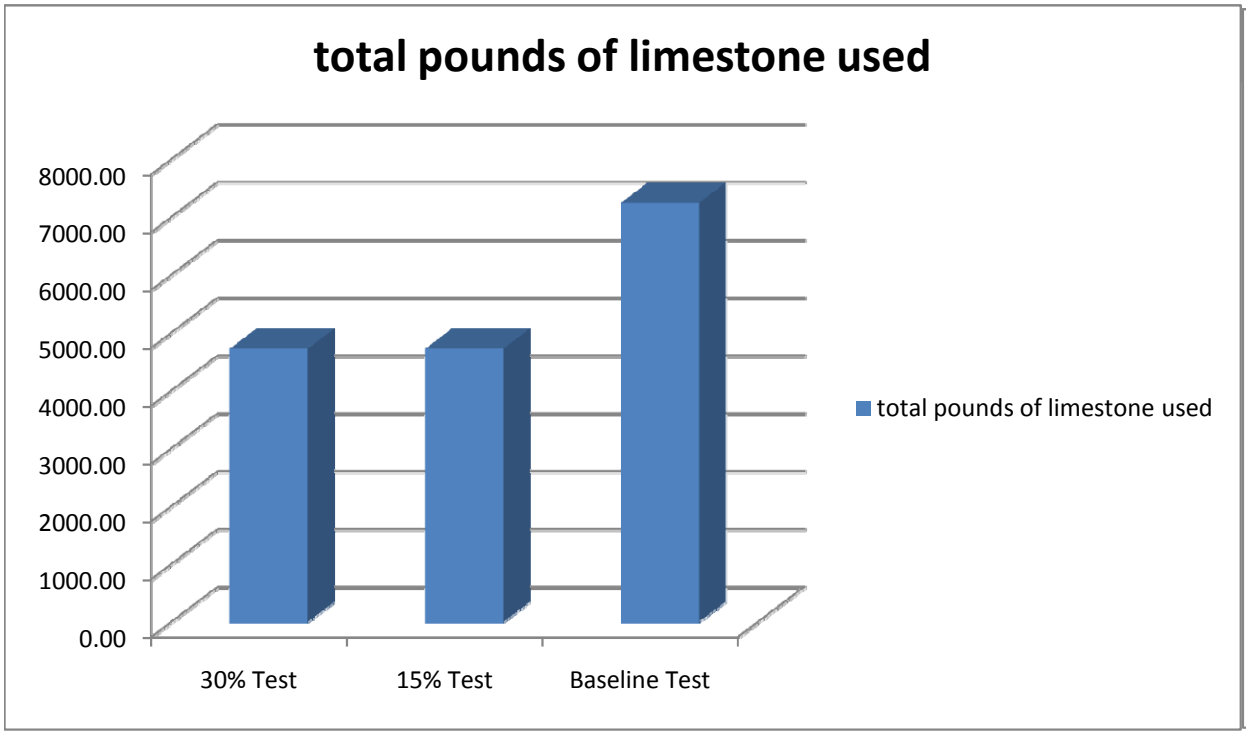
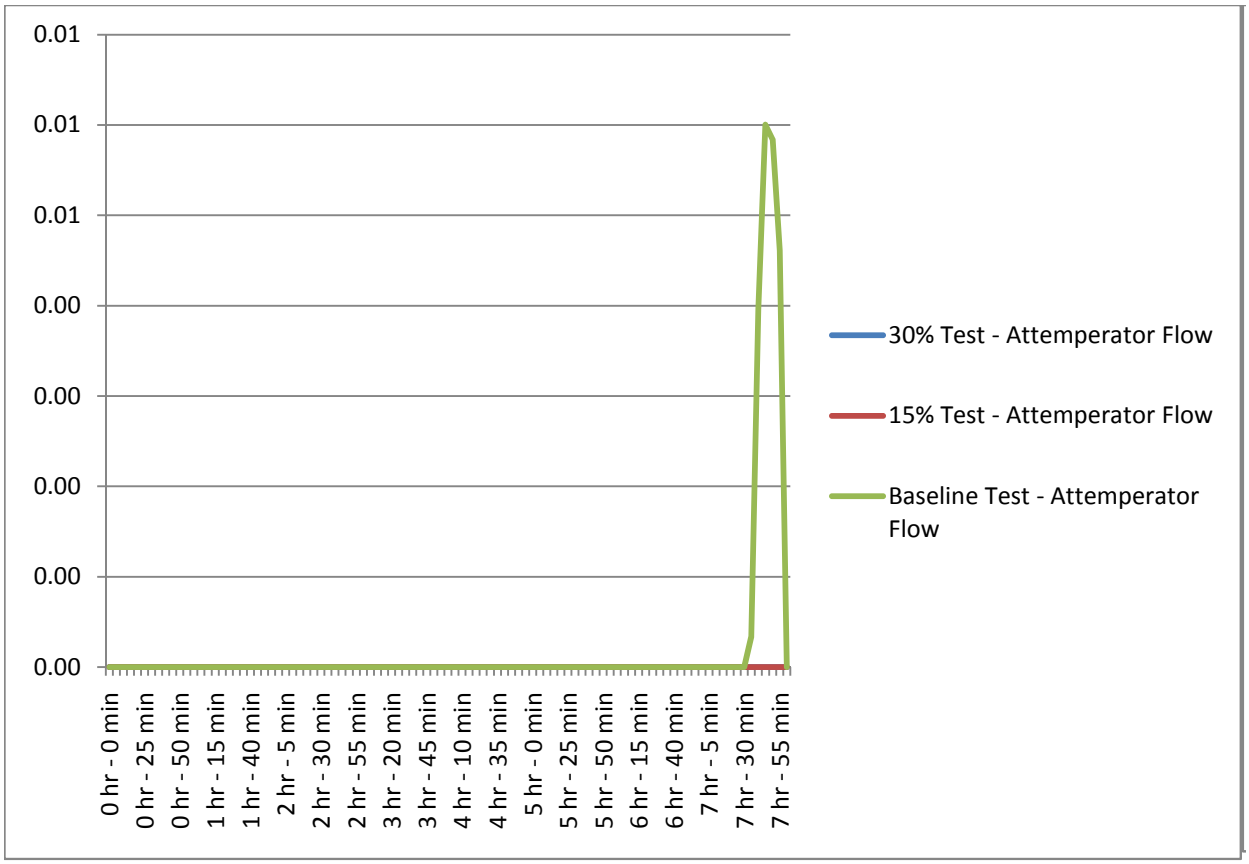
2 hr - 5 min
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - Limestone/Gravel Shots Put into Combuster
15% Test - Limestone/Gravel Shots Put into Combuster
Baseline Test - Limestone/Gravel Shots Put into Combuster


total pounds of limestone used
8000.00
7000.00
6000.00
5000.00
4000.00
3000.00
2000.00
1000.00
0.00
30% Test
15% Test
Baseline Test
total pounds of limestone used


0.01
0.01
0.01
0.00
0.00
0.00
0.00
0.00
0 hr - 0 min
0 hr - 25 min
0 hr - 50 min
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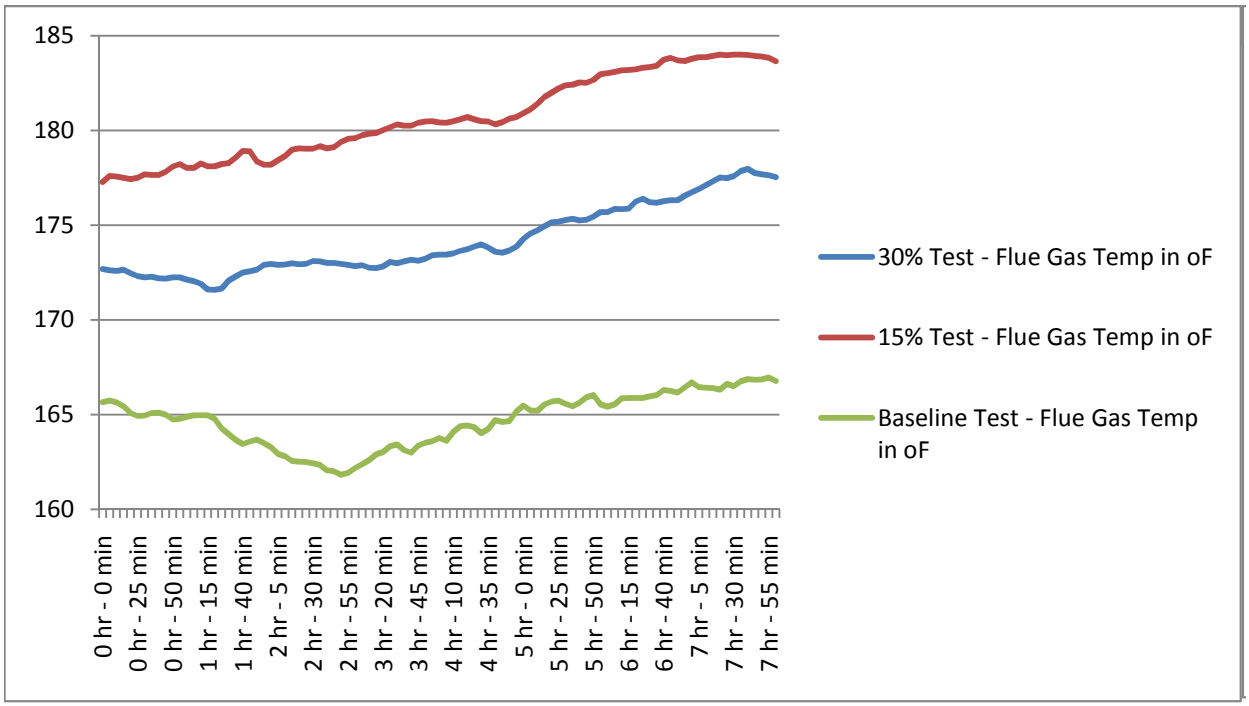
1 hr - 40 min
2 hr - 5 min
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - Attemperator Flow
15% Test - Attemperator Flow
Baseline Test - Attemperator Flow


185
180
175
170
165
160
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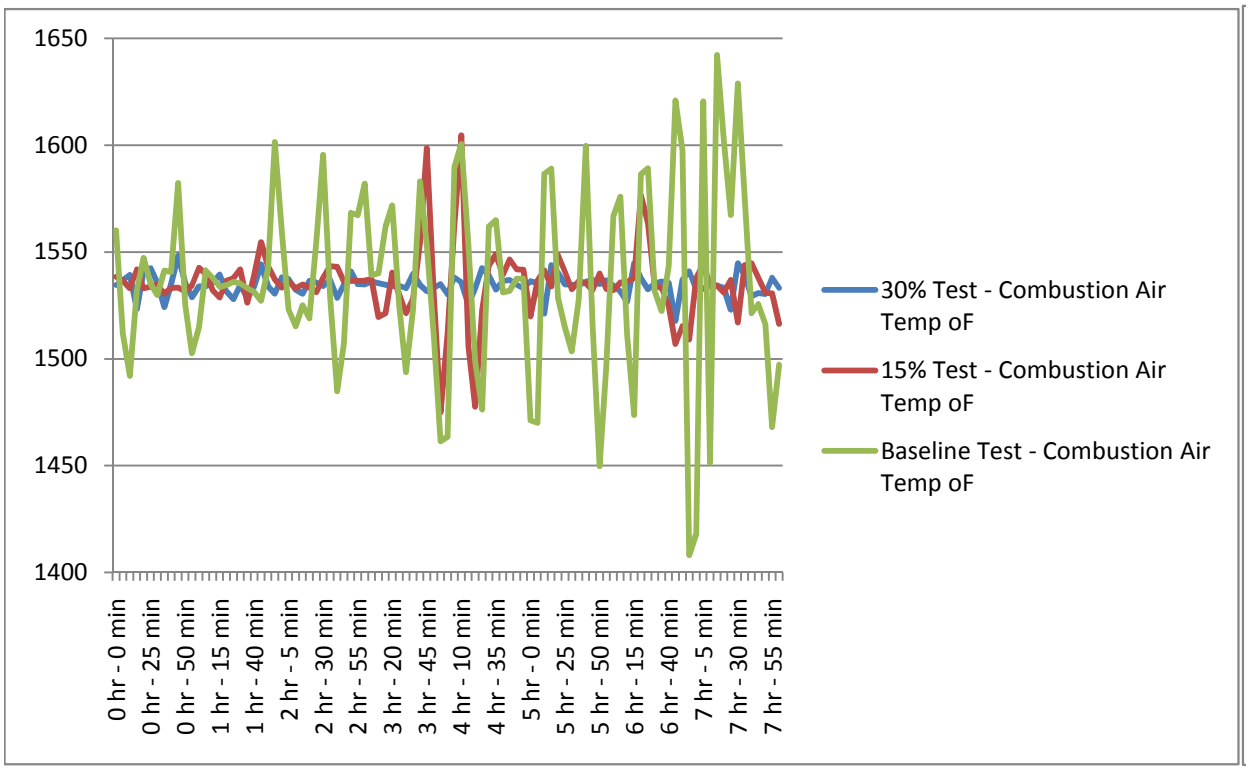
0 hr - 25 min
0 hr - 50 min
1 hr - 15 min
1 hr - 40 min
2 hr - 5 min
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - Flue Gas Temp in oF
15% Test - Flue Gas Temp in oF
Baseline Test - Flue Gas Temp in oF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1550
1500
1450
1400
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1 hr - 40 min
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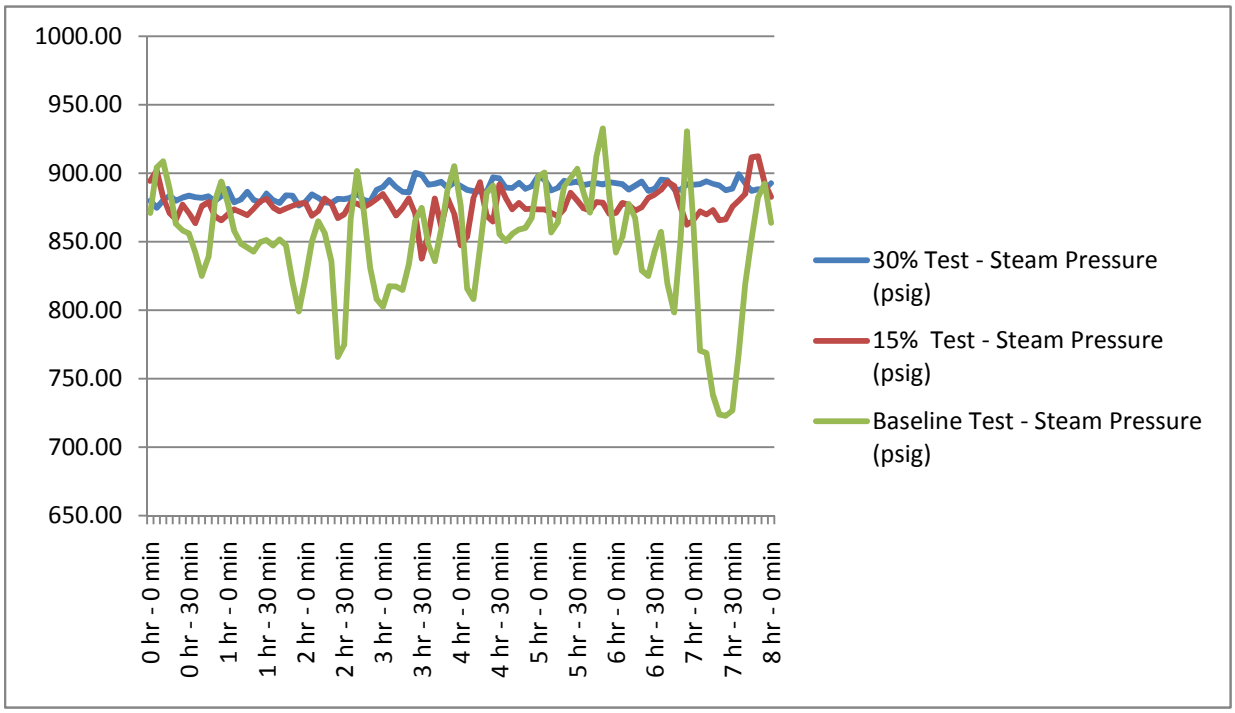
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - Combustion Air Temp oF
15% Test - Combustion Air Temp oF
Baseline Test - Combustion Air Temp oF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950.00
900.00
850.00
800.00
750.00
700.00
650.00
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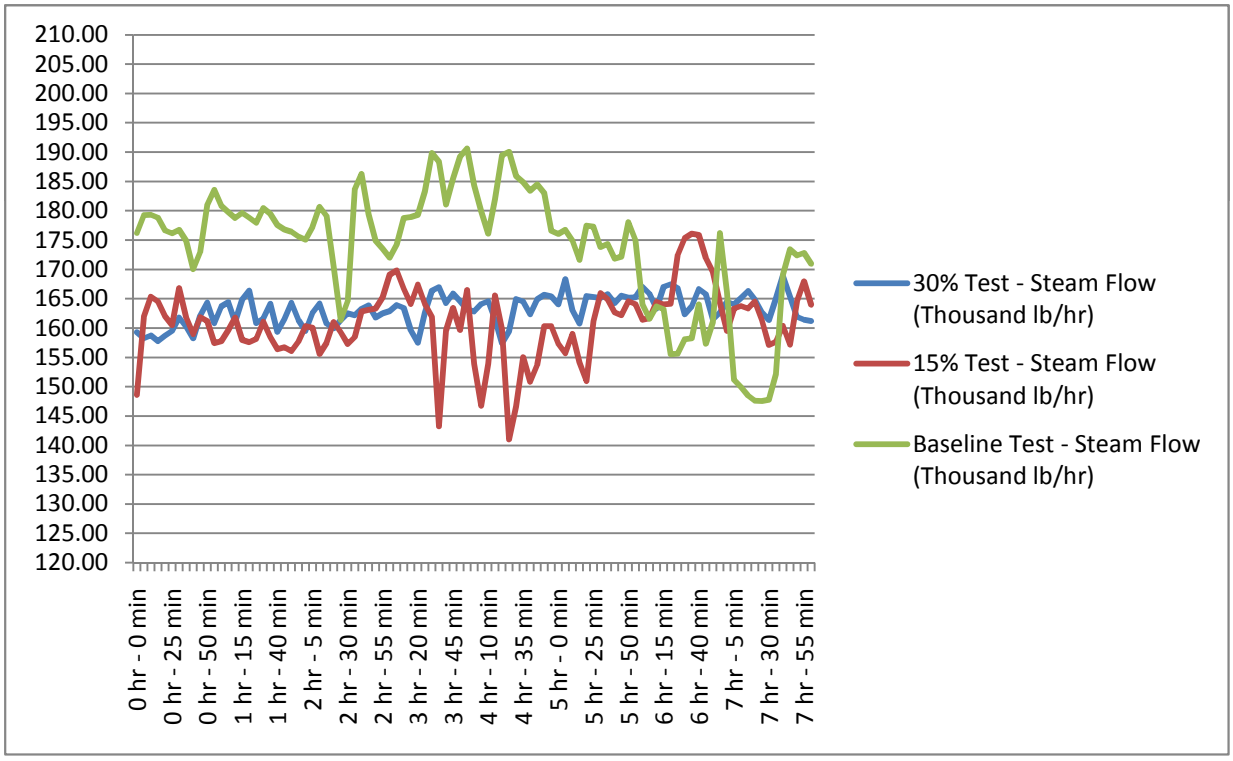
0 hr - 30 min
1 hr - 0 min
1 hr - 30 min
2 hr - 0 min
2 hr - 30 min
3 hr - 0 min
3 hr - 30 min
4 hr - 0 min
4 hr - 30 min
5 hr - 0 min
5 hr - 30 min
6 hr - 0 min
6 hr - 30 min
7 hr - 0 min
7 hr - 30 min
8 hr - 0 min
30% Test - Steam Pressure (psig)
15% Test - Steam Pressure (psig)
Baseline Test - Steam Pressure (psig)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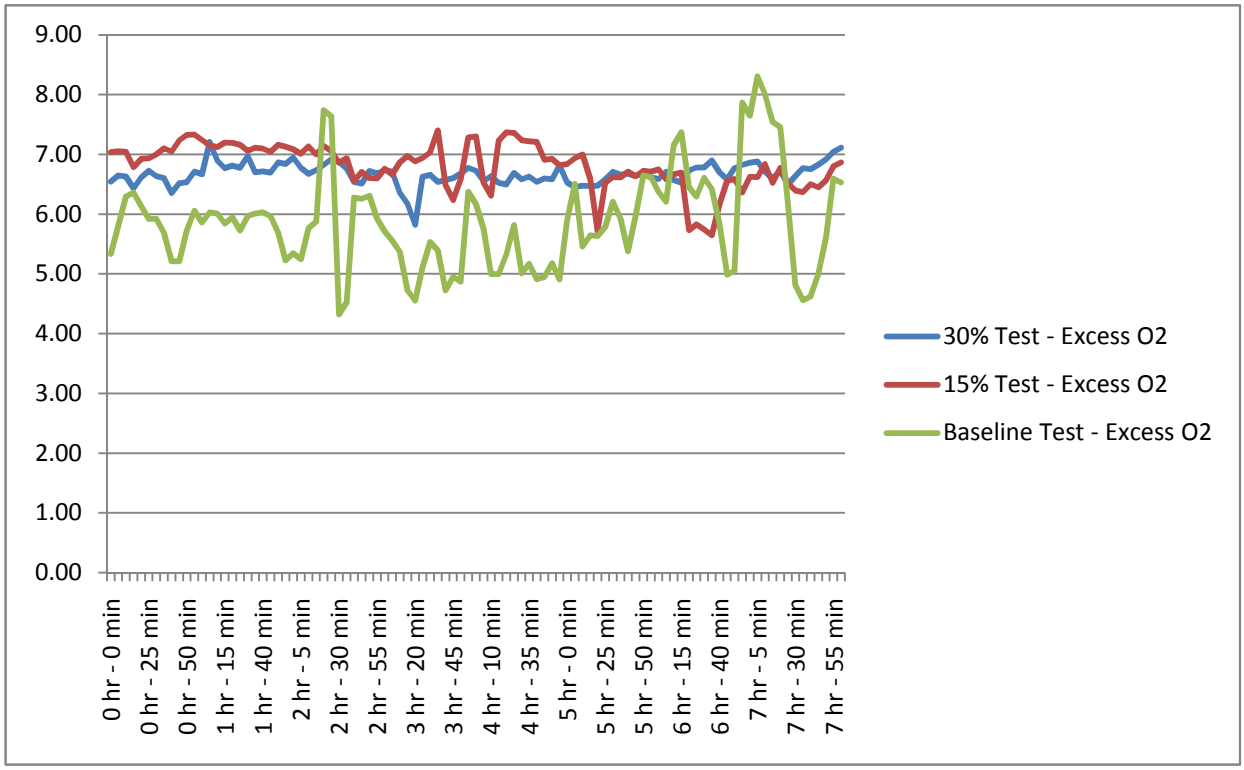
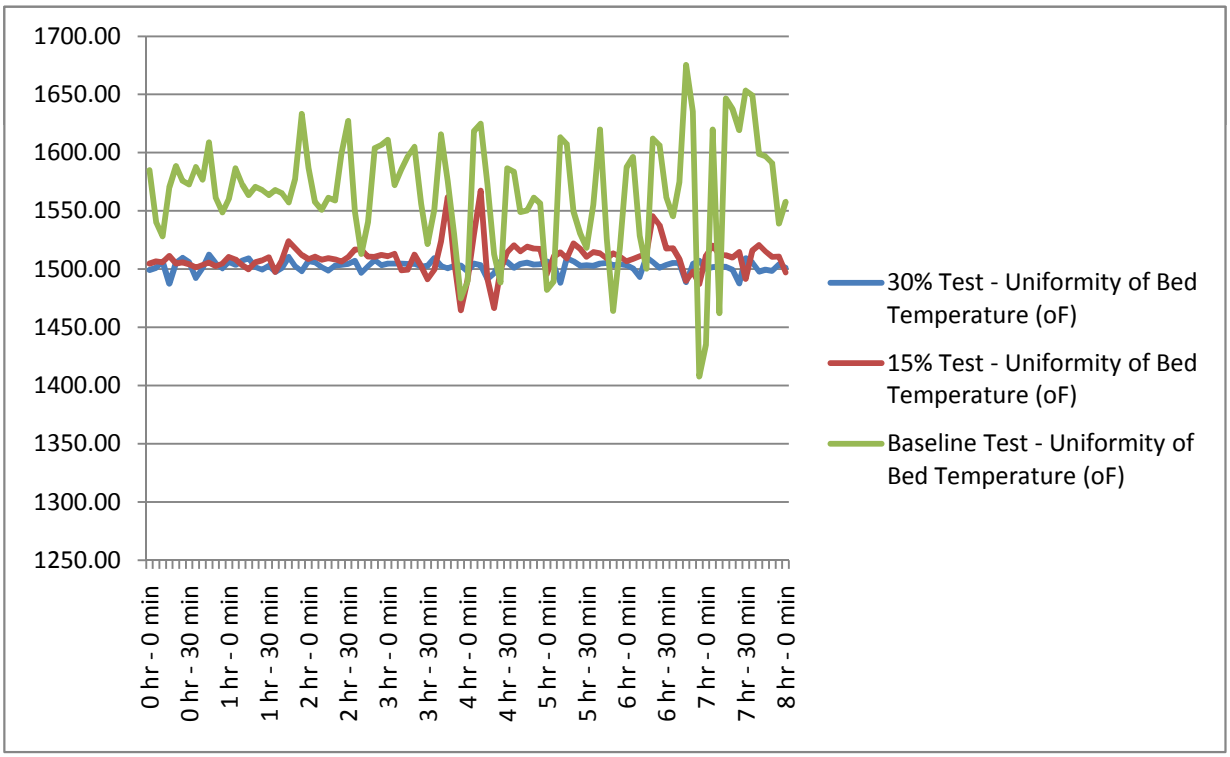
200.00
195.00
190.00
185.00
180.00
175.00
170.00
165.00
160.00
155.00
150.00
145.00
140.00
135.00
130.00
125.00
120.00
0 hr - 0 min
0 hr - 25 min
0 hr - 50 min
1 hr - 15 min
1 hr - 40 min
2 hr - 5 min
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - Steam Flow (Thousand lb/hr)
15% Test - Steam Flow (Thousand lb/hr)
Baseline Test - Steam Flow (Thousand lb/hr)


9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
0 hr - 0 min
0 hr - 25 min
0 hr - 50 min
1 hr - 15 min
1 hr - 40 min
2 hr - 5 min
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - Excess O2
15% Test - Excess O2
Baseline Test - Excess O2


1700.00
1650.00
1600.00
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1500.00
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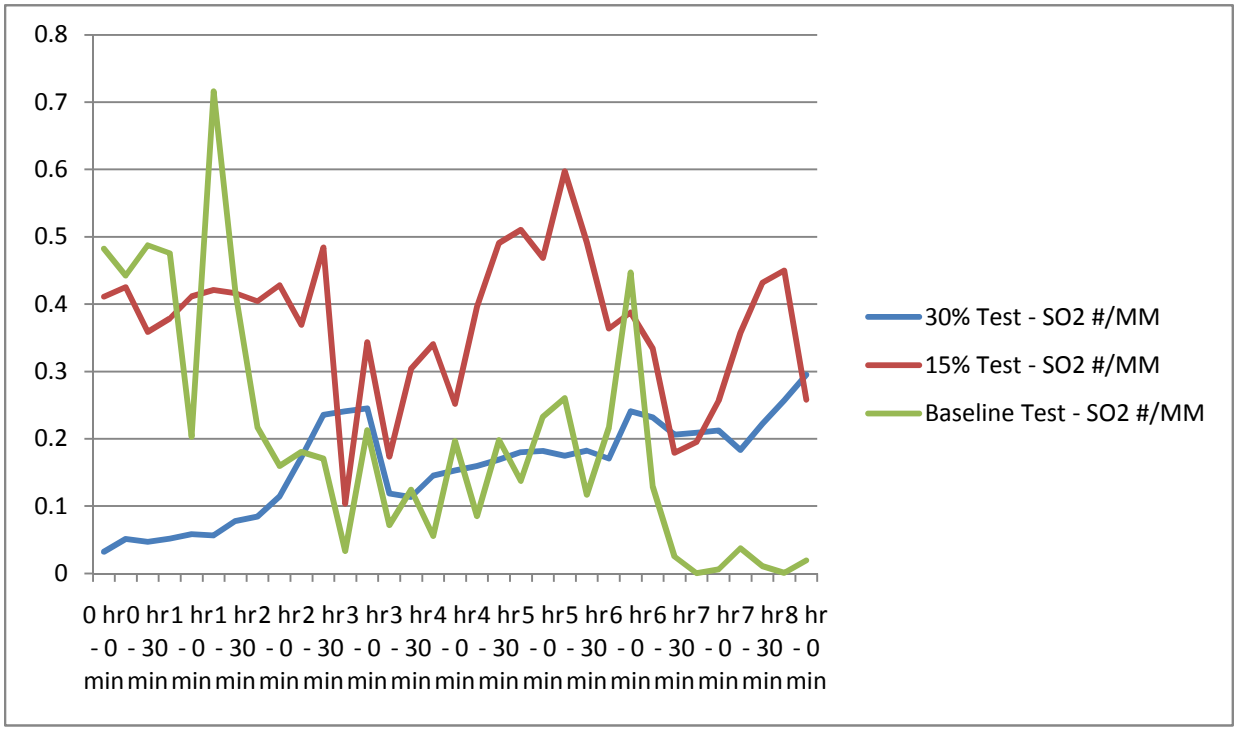
1400.00
1350.00
1300.00
1250.00
0 hr - 0 min
0 hr - 30 min
1 hr - 0 min
1 hr - 30 min
2 hr - 0 min
2 hr - 30 min
3 hr - 0 min
3 hr - 30 min
4 hr - 0 min
4 hr - 30 min
5 hr - 0 min
5 hr - 30 min
6 hr - 0 min
6 hr - 30 min
7 hr - 0 min
7 hr - 30 min
8 hr - 0 min
30% Test - Uniformity of Bed Temperature (oF)
15% Test - Uniformity of Bed Temperature (oF)
Baseline Test - Uniformity of Bed Temperature (oF)


0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0 hr - 0 min
0 hr - 30 min
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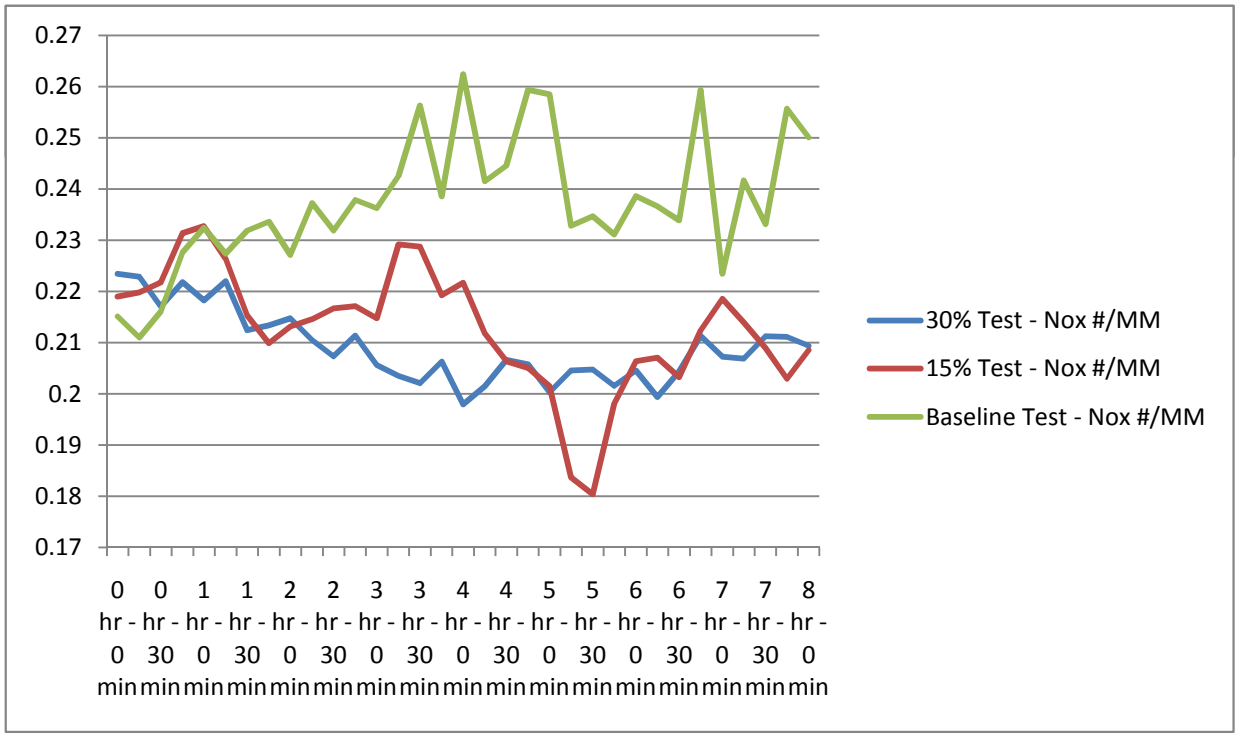
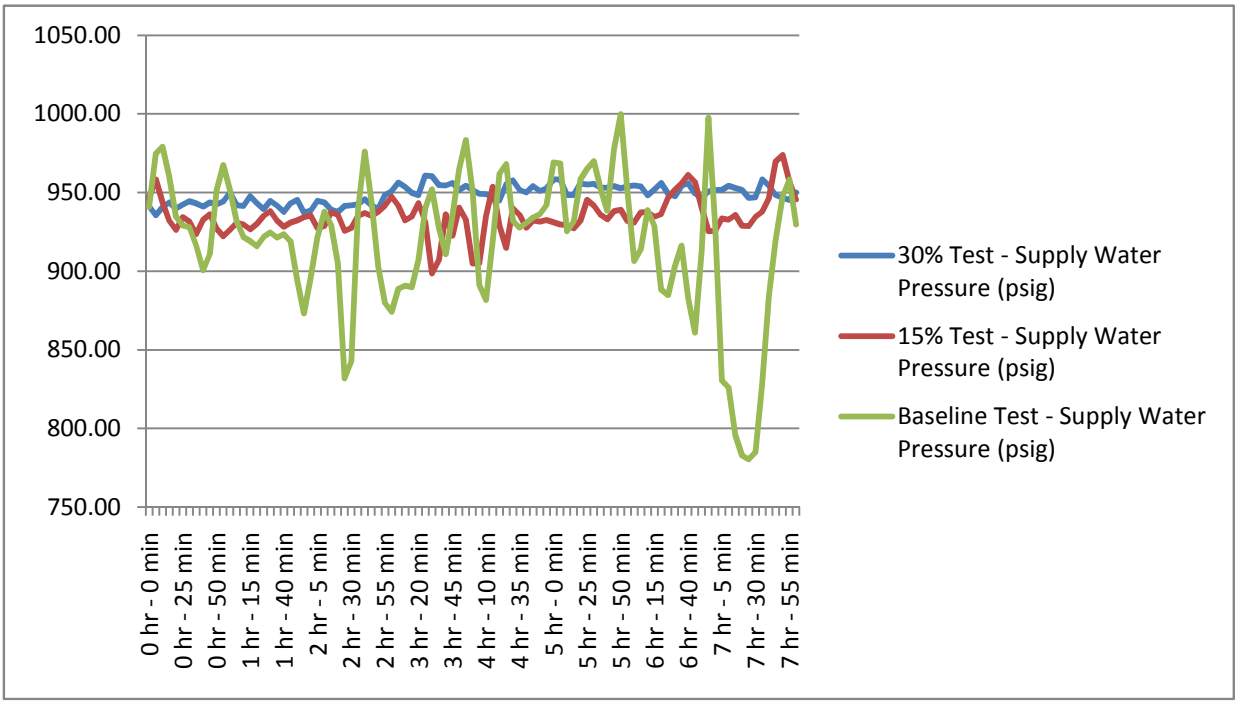
1 hr - 30 min
2 hr - 0 min
2 hr - 30 min
3 hr - 0 min
3 hr - 30 min
4 hr - 0 min
4 hr - 30 min
5 hr - 0 min
5 hr - 30 min
6 hr - 0 min
6 hr - 30 min
7 hr - 0 min
7 hr - 30 min
8 hr - 0 min
30% Test - SO2 #/MM
15% Test - SO2 #/MM
Baseline Test - SO2 #/MM


0.27
0.26
0.25
0.24
0.23
0.22
0.21
0.2
0.19
0.18
0.17
0 hr - 0 min
0 hr - 30 min
1 hr - 0 min
1 hr - 30 min
2 hr - 0 min
2 hr - 30 min
3 hr - 0 min
3 hr - 30 min
4 hr - 0 min
4 hr - 30 min
5 hr - 0 min
5 hr - 30 min
6 hr - 0 min
6 hr - 30 min
7 hr - 0 min
7 hr - 30 min
8 hr - 0 min
30% Test - Nox #/MM
15% Test - Nox #/MM
Baseline Test - Nox #/MM


1050.00
1000.00
950.00
900.00
850.00
800.00
750.00
0 hr - 0 min
0 hr - 25 min
0 hr - 50 min
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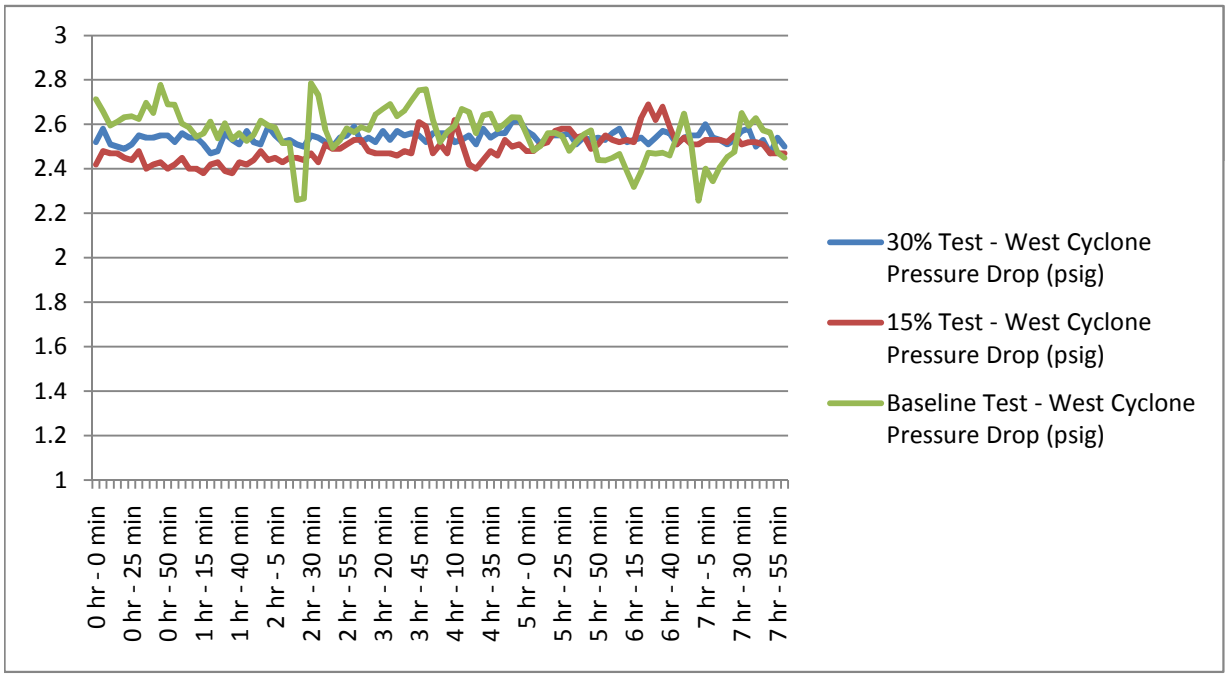
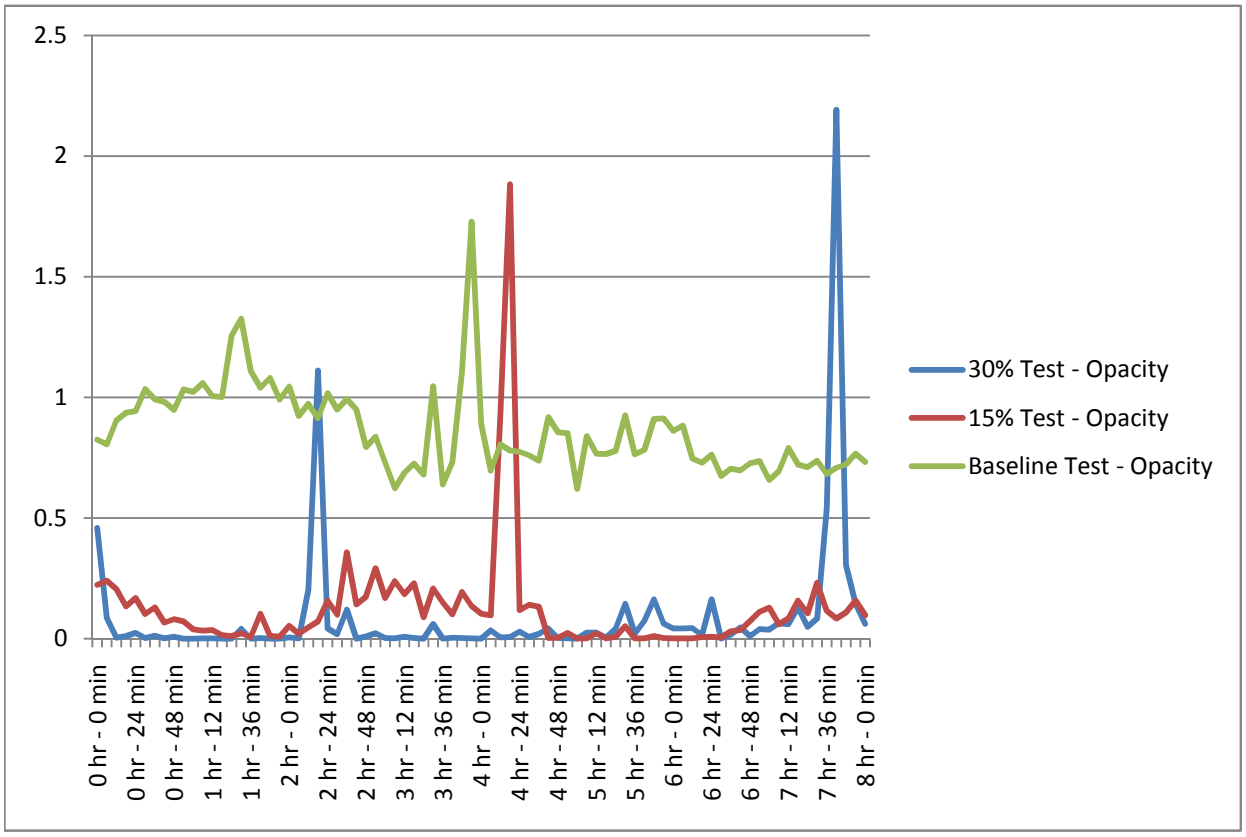
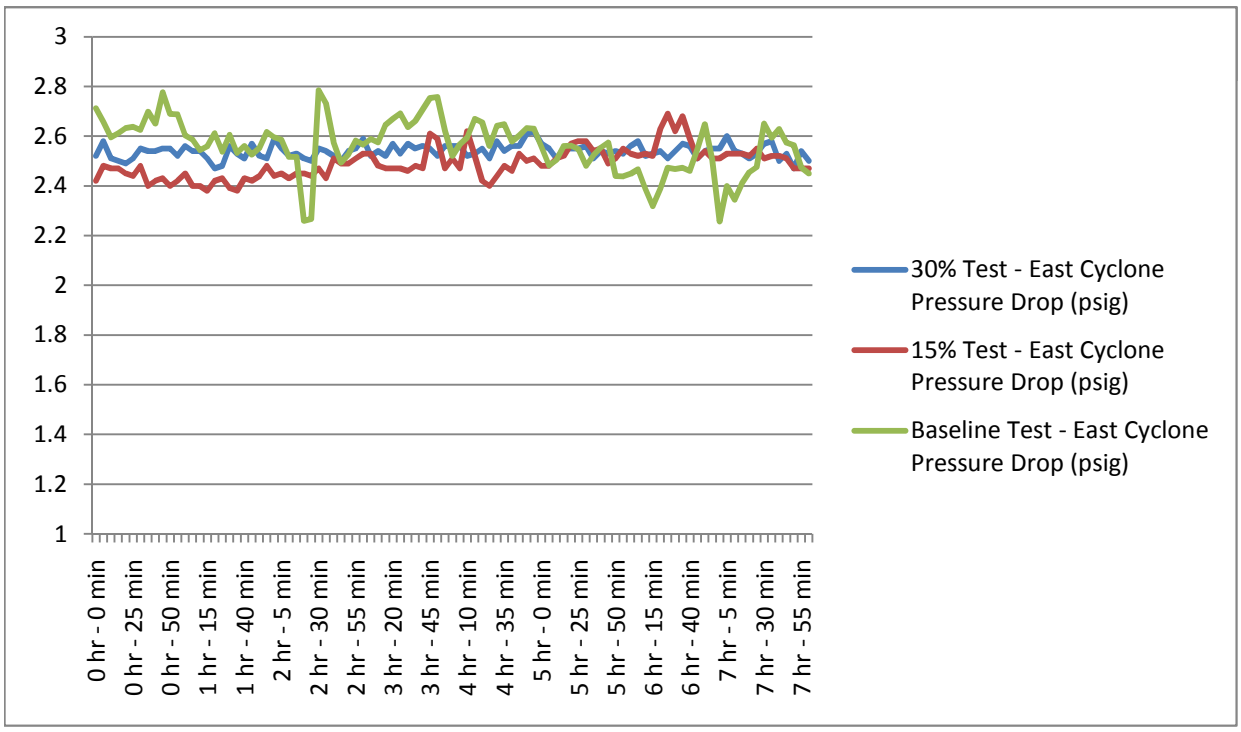
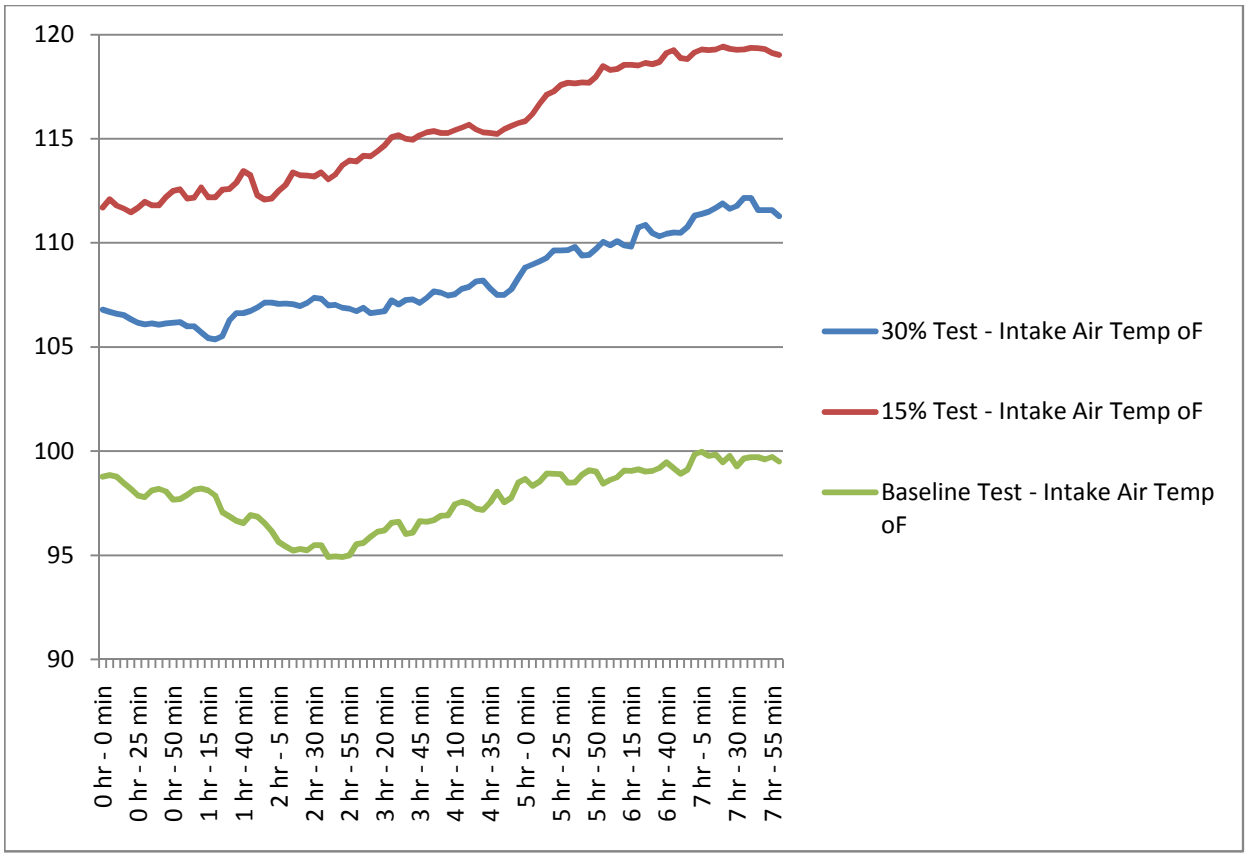
1 hr - 40 min
2 hr - 5 min
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - Supply Water Pressure (psig)
15% Test - Supply Water Pressure (psig)
Baseline Test - Supply Water Pressure (psig)


3
2.8
2.6
2.4
2.2
2
1.8
1.6
1.4
1.2
1
0 hr - 0 min
0 hr - 25 min
0 hr - 50 min
1 hr - 15 min
1 hr - 40 min
2 hr - 5 min
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - West Cyclone Pressure Drop (psig)
15% Test - West Cyclone Pressure Drop (psig)
Baseline Test - West Cyclone Pressure Drop (psig)


2.5
2
1.5
1
0.5
0
0 hr - 0 min
0 hr - 24 min
0 hr - 48 min
1 hr - 12 min
1 hr - 36 min
2 hr - 0 min
2 hr - 24 min
2 hr - 48 min
3 hr - 12 min
3 hr - 36 min
4 hr - 0 min
4 hr - 24 min
4 hr - 48 min
5 hr - 12 min
5 hr - 36 min
6 hr - 0 min
6 hr - 24 min
6 hr - 48 min
7 hr - 12 min
7 hr - 36 min
8 hr - 0 min
30% Test - Opacity
15% Test - Opacity
Baseline Test - Opacity


3
2.8
2.6
2.4
2.2
2
1.8
1.6
1.4
1.2
1
0 hr - 0 min
0 hr - 25 min
0 hr - 50 min
1 hr - 15 min
1 hr - 40 min
2 hr - 5 min
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - East Cyclone Pressure Drop (psig)
15% Test - East Cyclone Pressure Drop (psig)
Baseline Test - East Cyclone Pressure Drop (psig)


120
115
110
105
100
95
90
0 hr - 0 min
0 hr - 25 min
0 hr - 50 min
1 hr - 15 min
1 hr - 40 min
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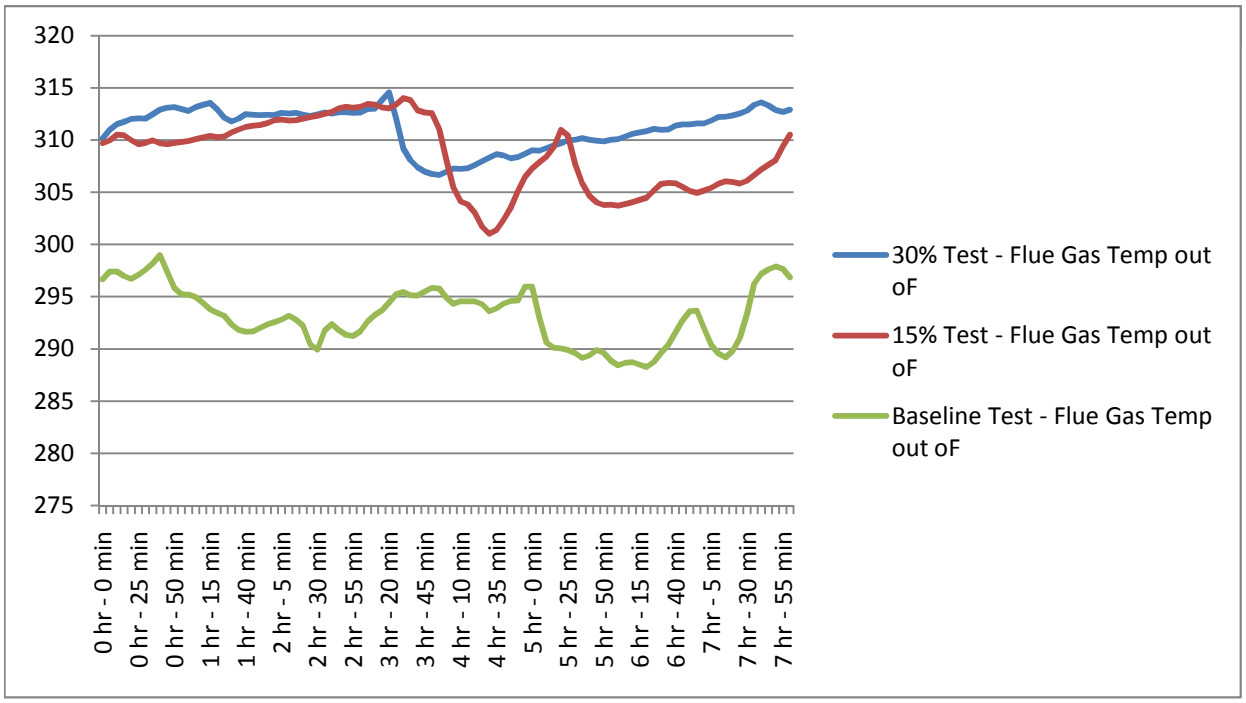
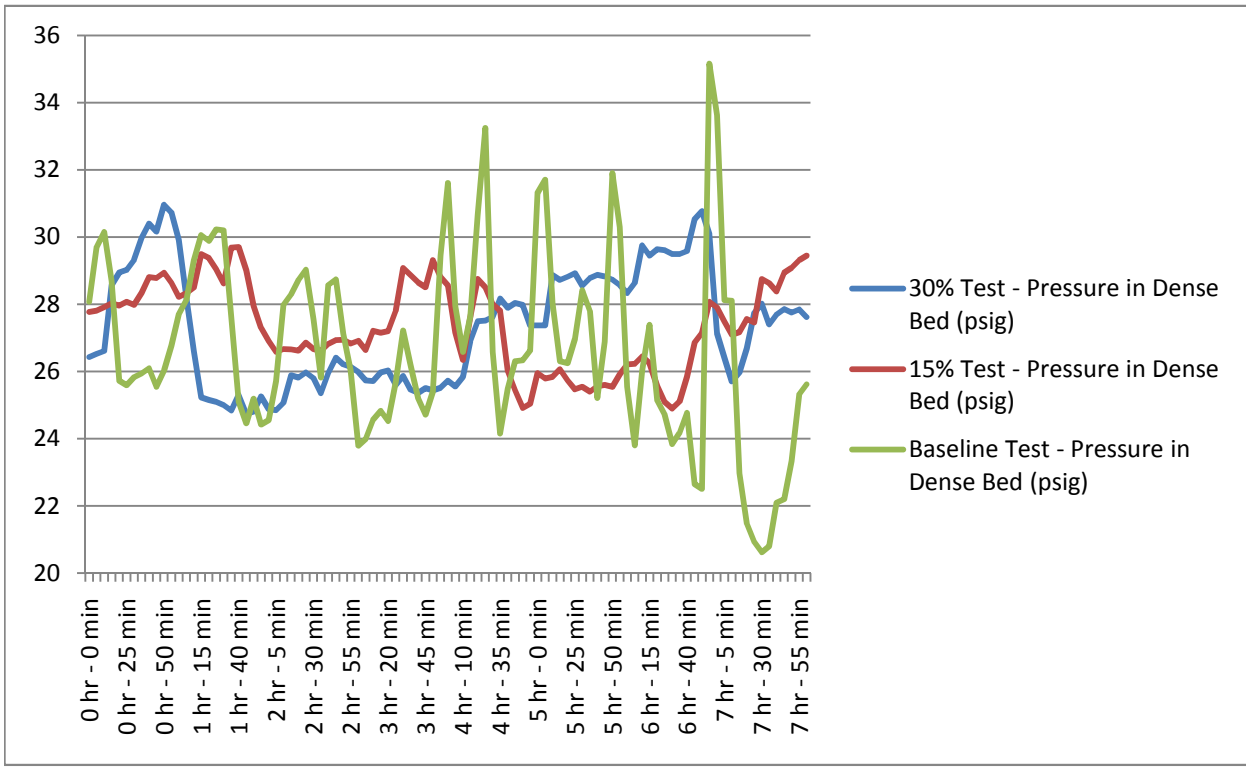
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - Intake Air Temp oF
15% Test - Intake Air Temp oF
Baseline Test - Intake Air Temp oF


320
315
310
305
300
295
290
285
280
275
0 hr - 0 min
0 hr - 25 min
0 hr - 50 min
1 hr - 15 min
1 hr - 40 min
2 hr - 5 min
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - Flue Gas Temp out oF
15% Test - Flue Gas Temp out oF
Baseline Test - Flue Gas Temp out oF


36
34
32
30
28
26
24
22
20
0 hr - 0 min
0 hr - 25 min
0 hr - 50 min
1 hr - 15 min
1 hr - 40 min
2 hr - 5 min
2 hr - 30 min
2 hr - 55 min
3 hr - 20 min
3 hr - 45 min
4 hr - 10 min
4 hr - 35 min
5 hr - 0 min
5 hr - 25 min
5 hr - 50 min
6 hr - 15 min
6 hr - 40 min
7 hr - 5 min
7 hr - 30 min
7 hr - 55 min
30% Test - Pressure in Dense Bed (psig)
15% Test - Pressure in Dense Bed (psig)
Baseline Test - Pressure in Dense Bed (psig)

Q. Test Burn Procedure

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10 Test Burn Completion Field Meeting 9
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Appendix B – Fuel Sample Log Form
Appendix C – Boiler Operator Visual Record
Appendix D – Pre-Test Checklist

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1 Overview

This test burn procedure is designed to evaluate boiler performance when co-firing clean extruded wood biomass with coal in the Wyandotte Municipal Services (WMS) Unit #8 Boiler. This test burn will evaluate co-firing WMS's normal 60/40 blend of PRB Coal/TDF fuel with renewaFUEL's clean extruded one hundred percent wood biomass product.

Changes in operational performance with regard to efficiency, emissions, and fly ash characteristics will be evaluated while combusting one-hundred percent PRB coal/TDF and then reevaluated while co-firing biomass with PRB coal/TDF at steady state conditions (steam flow and fuel mixtures) in multiple ratios.

The following general testing approach will be followed:

1) Perform Baseline test with 60/40 blend of PRB Coal/TDF fuel.
2) Collect performance data under (a) typical operating mode and (b) while burning a blend of coal/TDF and the wood biomass fuel.
3) Analyze the test results to evaluate changes in boiler emissions performance attributable to wood biomass co-firing.

The baseline test will be completed one to two weeks prior to the renewaFUEL biomass test burns to provide an opportunity to test the data collection procedures with the controller's, operators, and field personnel who will complete the work.

2 Responsibilities

A representative of Barr/ WMS will coordinate testing activities with the boiler operators to confirm that all testing is conducted at the desired boiler operating set points and the boiler operational data needed to calculate efficiency is properly logged and stored. Barr will supervise the field testing activities. Daily log forms attached in appendices will be used to document test periods and conditions.

Barr will plan and manage the following aspects of the test burn:

1) Confirming that sufficient uniform source of wood biomass is available for testing
2) Scheduling of test activities to minimize impact on site operations
3) Identifying safe access to the test location
4) Coordinating subcontractors and analytical laboratories

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WMS will be responsible for any procedure that is associated with Unit #8 normal operations including but not limited to:

1) Fuel storage site preparation
2) Fuel conveyance
3) Boiler operations
4) Equipment operations
5) Visual recording of combustion zone
6) Fuel sampling at gravimetric feeders
7) Data collection using existing CEMS, DCS and PI systems

3 Test Burn Monitoring Parameters

Specifically, the operating points tested will be: the boiler firing PRB coal/TDF only at a typical steam capacity, of 180,000 lb/Hr and the boiler firing wood biomass/PRB Coal/TDF mixture at its normal fuel blend at the same operating load. By limiting the testing to normal operational points, the approach minimizes the chance of other operational changes within the boiler from masking the effect of co-firing.

The verification parameters listed below will be evaluated. This list was developed based on project objectives cited by the client.

1) Boiler efficiency during biomass co-firing and normalize emissions to boiler output
2) Changes in emissions
    a. Nitrogen oxides (NO_x)
    b. Sulfur dioxide (SO_2)
    c. Carbon monoxide (CO)
    d. Carbon dioxide (CO_2)
    e. Total particulates (TPM),via opacity
3) Changes in fly ash characteristics including:
    a. Carbon, hydrogen, and nitrogen (CHN), and minerals content
    b. Primary metals: arsenic (As), selenium (Se), zinc (Zn), and mercury (Hg)
    c. Secondary metals: barium (Ba), beryllium (Be), cadmium (Cd), chromium (Cr), copper (Cu), manganese (Mn), nickel (Ni), and silver (Ag)
    d. Potential boiler fouling components: calcium (Ca), sodium (Na), and potassium (K)
    e. Fly ash fusion temperature
    f. RCRA metals TCLP
    g. Air entraining agent index

Boiler efficiency will be observed using WMS Digital Control Systems (DCS) screen shots during the baseline test and then calculated with the PI historian software data collected during the baseline test. The same process of using the PI historian software data collection and the DCS screen shots will be

completed during the biomass test burn conditions. The observations and calculated data will then be compared to one another to determine if the boiler efficiency was altered during the biomass testing.

Boiler efficiency parameters:

1) Intake air temperature, ^{o}F
2) Flue gas temperature at air heater inlet and outlet, ^{o}F
3) Fuel temperature, ^{o}F
4) Moisture in air, lb/lb dry air
5) Fuel consumption, lb/hr
6) Combustion air temperature, ^{o}F
7) Steam flow, MMBtu/h or lb/h
8) Steam pressure, psig
9) Steam temperature, ^{o}F
10) Supply water pressure, psig
11) Supply water temperature, ^{o}F
12) Power generation, kW
13) Fuel ultimate analyses, both wood and coal
14) Fuel heating value, Btu/lb
15) Unburned carbon loss, %
16) Excess O_2 or air

The primary focus of each biomass test burn is to monitor the boiler output of the test materials to determine boiler capacity. Fan horse power and air/flue gas flows will also be monitored to aid in determining biomass boiler capacity.

A verbal record of the operating stability will be documented along with a steam pressure plot to determine the operating stability differences during the baseline test and the biomass test burns.

The following items will be monitored to help determine the bed operations during the baseline test and also the biomass test burns.

1) Screen shot data
2) Bed temperature
3) Uniformity of bed temps
4) Pressure drop – air and flue gas
5) Visual observations of the bed
6) Functioning of the external heat exchanger
7) Bed inventory

4 Proposed Tests – Durations and Biomass Tonnages

The renewaFUEL biomass will be tested in the Unit #8 boiler using the sequence described below (for a total of two tests).

Table 4-1 Biomass Co-firing Program Test Matrix			
Test	Fuel Blend	Test Day	Test Durations and Sampling Frequency
Baseline	100% PRB Coal/TDF fuel blend (sample coal and flyash prior to biomass test)	Prior to Outage	- 1 test, 8 hours in duration
Test #1 –	30 % renewaFUEL wood biomass product and 70% PRB Coal/TDF fuel blend	Test Day #1 June 8th	- 20 hours operation at steady state conditions (steam flow and fuel mixture) at 30% biomass, then collect test samples for a period of 8 hours - Test duration 28 hrs
Test #2 –	60% renewaFUEL wood biomass product and 40% PRB Coal/TDF fuel blend	Test Day #2 June 10th	- Immediately ramp up to 60% biomass after Test #1 - 20 hours operation at steady state conditions (steam flow and fuel mixture) at 60% biomass, then collect test samples for a period of 8 hours - Test duration 28 hrs
Note: All biomass tests will be run at a boiler output goal of 180,000 lb/hr or as determined during baseline test.			

The anticipated tonnages of renewaFUEL are summarized in the following table.

Table 4-2 - 100% Wood			
Test Number	Duration hours	Hourly Flow Rate Tons/hr	Total Test tons
Test #1@ 30% Biomass	28	6	165
Test #2 @ 60% Biomass	28	12	335
		Total Consumed	500

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All testing will be conducted during steady state boiler operations (steam flow and fuel mixture). Test and sampling procedures will be as consistent as possible between sets of tests. Any problems occurred during testing will be recorded to help define anomalies.

5 Fuel Handling Procedures

Prior to delivery of the biomass fuel, WMS will empty the Unit #8 limestone silo. The biomass will be stored in the Unit #8 limestone silo for the duration of the testing.

Prior to conveying the biomass fuel into the Unit #8 limestone silo, WMS will clear the reclaim area and also clear the belts.

The renewaFUEL product will be delivered via 35 ton truck. The trucks will use a walking bed to unload fuel into the WMS coal yard. The biomass fuel will be dumped onto the Unit #8 Grizzly and fed into the reclaim. The fuel will be delivered via the Unit #8 Reclaim onto the Unit #8 conveyer to the Unit #8 limestone silo. The Unit #8 limestone silo will be filled with 100% biomass, approximately 84 tons capacity. The Unit #8 bunker will be filled with the normal 60/40 blend of PRB Coal/TDF fuel. The biomass feed rate will be controlled by the existing gravimetric feeder.

Delivery of the biomass will be coordinated to meet the requirements of the two tests described in Table 4-1. The limestone silo will need to be filled several times during each test.

After the test burns are completed the boiler and fuel handling equipment will be positioned for normal operating conditions.

6 Pre-test Check List

Boiler operations verifying the following shall be completed by the WMS boiler operators prior to each test burn.

1) Boiler is operating at 180,000 lb/hr
2) Bed operation is stable
3) Boiler is stable
4) No coal feeder issues
5) No boiler feed pump issues
6) Control room operator is ready for test
7) Shift supervisor is ready and located where needed
8) Correct fuel is located in the correct bunkers for fuel feed
9) Computer system is up and running
10) All data to be collected is being recorded
11) Existing baghouse has one hopper emptied to ensure PRB Coal/TDF fly ash is not included in fly ash sampling

12) Fuel handling system is clean of all PRB Coal/TDF fuel to ensure an accurate reading of the biomass test burn emissions
13) Staff are in the correct location and prepared to complete their assigned tasks

7 Data Collection

The following DCS data points will be collected using the PI Historian software system which allows the facility to customize data acquisition, storage, and reporting activities. The boiler is also equipped with continuous emission monitoring systems (CEMS) that record NO_x, SO_2, CO, and O_x concentrations and emission rates.

Operation parameters that will be recorded during this test program include the following:

1) Intake air temperature, ^oF
2) Flue gas temperature at air heater inlet and outlet, ^oF
3) Fuel temperature, ^oF (manually with a heat gun)
4) Fuel consumption, lb/hr
5) Combustion air temperature, ^oF
6) Steam flow, MMBtu/h or lb/h
7) Steam pressure, psig
8) Steam temperature, ^oF
9) Supply water pressure, psig
10) Supply water temperature, ^oF
11) Power generation, kW
12) Fuel ultimate analyses, both wood and coal
13) Fuel heating value, Btu/lb
14) Unburned carbon loss, %
15) Excess O_2 or air
16) Power output (MW)
17) Heat input for coal, wood, and total, (Btu/hr)
18) Coal and wood feed rates via belt scales, (lb/hr)
19) Emissions
    a. Nitrogen oxides (NO_x), CEM
    b. Sulfur dioxide (SO_2), CEM
    c. Carbon monoxide (CO)
    d. Carbon dioxide (CO_2), CEM
    e. Total particulates (TPM), via opacity
20) Multiclone pressure drop (in w.c.)
21) Bed temperature
22) Uniformity of bed temps
23) Pressure drop across the bed
24) Visual observations of the bed

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25) Functioning of the external heat exchanger
26) Visual observation of fugitive dust

These data points will be collected on a five minute basis during the baseline test and for the each biomass test burn and exported to an excel spreadsheet.

Fuel samples will be taken from the gravimetric feeders for the 100% renewaFUEL clean extruded wood biomass product and the PRB Coal/TDF fuel blend. The samples will be taken on 30 minute intervals, marked with the date and time taken, sealed and sent to an independent testing facility.

A flyash sample will need to be collected at the completion of each test. Prior to starting the biomass test burns the baghouse dust collection hoppers shall be emptied. This will ensure that a representative sample for the biomass test burn is collected. At the completion of each test burn a flyash sample shall be collected.

8 Results and Data Compilation

Upon completion of testing the following data compilation will be performed. The results will be presented in a final report completed by Barr.

At the conclusion of field testing, results will be analyzed to evaluate changes in boiler performance, fly ash characteristics, and to verify the statistical significance of any observed changed in emissions or efficiency between tests and renewaFUEL products.

Data recorded on each test period will be averaged over the test period and reported to document boiler operations during the testing, co-firing rates, and boiler efficiency.

The ultimate analysis will report the following fuel constituents as percent by weight:

1) Carbon
2) BTU
3) Water/Moisture
4) Ash
5) Sulfur
6) Hydrogen
7) Oxygen
8) Nitrogen
9) Fines/Including wood species

The fly ash samples will be sent to a lab for testing of the following changes in fly ash characteristics including:

1) Carbon, hydrogen, and nitrogen (CHN), and minerals content

2) Primary metals: arsenic (As), selenium (Se), zinc (Zn), and mercury (Hg)
3) Secondary metals: barium (Ba), beryllium (Be), cadmium (Cd), chromium (Cr), copper (Cu), manganese (Mn), nickel (Ni), and silver (Ag)
4) Potential boiler fouling components: calcium (Ca), sodium (Na), and potassium (K)
5) Fly ash fusion temperature
6) RCRA metals TCLP
7) Air entraining agent index

9 Daily Log

The following daily logs will be recorded for each test.

The boiler operator will be responsible for the log attached form located in appendix A.

The visual observations of how the biomass fuel is delivering into boiler, confirmation the boiler is operating correctly, record of any operating problems that have occurred prior to test, and also view port recordings will be completed by experienced WMS on-site staff for each test and recorded on the attached form located in appendix B.

The Pre-test checklist attached in appendix C will be completed by WMS staff prior to each test.

A fuel sample log form will be completed every 30 minutes by WMS staff during each test

10 Test Burn Completion Field Meeting

Immediately following each test, a meeting will be held to collect the log sheets, fuel samples and record comments from the biomass testing and any observations made by the testing personnel. A thorough review of any record of operating problems will be reviewed along with any fuel handling concerns, such as, whether WMS had to poke the bunker to get the fuel to flow at any point during testing or if the boiler output goal of 180,000 lb/hr deviated during the test cycle.

Upon completion of the biomass testing the required activities to switch back to normal PRB Coal/TDF operation will begin, by WMS. Barr will remain on-site to observe and confirm the change over from biomass to PRB Coal/TDF is seamless and also be available to help resolve issues as they may occur.

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UNIT # 8 renewaFUEL BIOMASS TEST BURN

BOILER OPERATOR TEST LOG FORM

Project ID: _____ Date:_____

Unit Description:_____ Signature:_____

Test Description:_____ Test No.:_____

_____ Clock Synch performed (Initials):_____

	Start	½ hr	1 hr	1 ½ hr	2 hr	2 ½ hr	3 hr	3 ½ hr	4 hr	4 ½ hr	5 hr	5 ½ hr	6 hr	6 ½ hr	7 hr	7 ½ hr	End
Time																	
Biomass Blend Rate, %																	
Steam Flow, lb/hr																	
Steam Pressure @ boiler outlet, psig																	
Steam Temperature @ boiler outlet, °F																	
Combustion Air Temp., °F (downstream of air heater)																	
Ambient Air Temp., °F (upstream of air heater)																	
Generating Rate, kW																	

Notes:

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UNIT # 8 renewaFUEL BIOMASS TEST BURN

FUEL SAMPLE LOG FORM

Project ID: _____ Date:_____

Unit Description:_____ Signature:_____

Test Description:_____ Test No.:_____

_____ Clock Synch performed (Initials):_____

Biomass Sample	Start	½ hr	1 hr	1 ½ hr	2 hr	2 ½ hr	3 hr	3 ½ hr	4 hr	4 ½ hr	5 hr	5 ½ hr	6 hr	6 ½ hr	7 hr	7 ½ hr	End
Time																	
Quantity																	
Initials of Sampler																	
PRB Coal/TDF Sample	**Start**	**½ hr**	**1 hr**	**1 ½ hr**	**2 hr**	**2 ½ hr**	**3 hr**	**3 ½ hr**	**4 hr**	**4 ½ hr**	**5 hr**	**5 ½ hr**	**6 hr**	**6 ½ hr**	**7 hr**	**7 ½ hr**	**End**
Time																	
Quantity																	
Initials of Sampler																	

Ash Sample	Start	End
Time		
Quantity		
Initials of Sampler		

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UNIT # 8 renewaFUEL BIOMASS TEST BURN

BOILER OPERATOR VISUAL RECORD

Project ID: _____ Date:_____

Unit Description:_____ Signature:_____

Test Description:_____ Test No.:_____

_____ Clock Synch performed (Initials):_____

Operating Problems Occurring Prior Test:

Fuel Delivery Visual Observations:

Boiler Operation Notes:

Boiler Bed Notes:

Operating Problems Occurring During Test:

Other Notes:

*VISUAL OBSERVATIONS TO BE RECORDED EACH HOUR OF TESTING

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UNIT # 8 renewaFUEL BIOMASS TEST BURN

PRE-TEST CHECKLIST

Project ID: _____ Date:_____

Unit Description:_____ Signature:_____

Test Description:_____ Test No.:_____

_____ Clock Synch performed (Initials):_____

- ☐ Boiler is operating at 160,000 lb/Hr
- ☐ Bed operation is stable
- ☐ Boiler is stable
- ☐ No coal feeder issues
- ☐ No boiler feed pump issues
- ☐ Control room operator is ready for test
- ☐ Shift supervisor is ready and located where needed
- ☐ Correct fuel is located in the correct bunkers for fuel feed
- ☐ Computer system is up and running, both PI and CEM's
- ☐ All data to be collected is being recorded
- ☐ Existing baghouse has one hopper emptied to ensure PRB Coal/TDF fly ash is not included in fly ash Sampling
- ☐ Staff are in the correct location and prepared to complete their assigned tasks

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R. Traverse City Report

Business Confidential

Integrated Resource Plan

Traverse City Light and Power

February 2010

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Integrated Resource Plan

Traverse City Light and Power

February 2010

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This report has been prepared for the use of the client for the specific purposes identified in the report. The conclusions, observations and recommendations contained herein attributed to R. W. Beck, Inc. (R. W. Beck) constitute the opinions of R. W. Beck. To the extent that statements, information and opinions provided by the client or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate, and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report.

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Integrated Resource Plan

Traverse City Light and Power

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Introduction

Traverse City Light and Power ("TCLP") is a municipally-owned entity of the City of Traverse City (the "City") established in 1912, which is governed by an Electric Utility Board. TCLP provides electric service to a mix of residential, commercial, and diversified industrial customers totaling approximately 11,000 customers within the City's geographic limits and surrounding areas. TCLP's mission is to provide affordable rates, ensure high levels of customer satisfaction, and provide reliable utility service to its customers. In 2008, TCLP had a total annual load of approximately 343,000 megawatt-hours (MWh) and summer peak demand of 64.9 megawatts (MW). The 2009 summer peak demand was approximately 67 MW, which was lower than the projected value of 74.6 MW as a result of the economic recession and mild weather.

Based on TCLP's commitment to provide reliable electric service and the long-term investments and strategies needed to address growing electric demand in its service territory, TCLP has commissioned R.W. Beck to conduct an integrated resource planning study ("IRP Study") over a study period 2009-2028 ("Study Period"). The integrated resource plan ("IRP") is a long-term (20-year) comprehensive energy resource plan to meet TCLP's projected electric power requirements. The IRP is based on detailed computer modeling techniques and risk analysis, and includes energy efficiency programs, an expanded renewables program, the utilization of existing generation resources, and the development of new, local electric power generation. The IRP provides a strategy that is designed to meet the objectives of balancing cost, risk and reliability for customers in light of the significant uncertainties that exist in the energy industry. The IRP reflects TCLP's best efforts on how to meet customer energy needs over the next two decades in a balanced manner.

This IRP Study was performed under that certain agreement dated April 20, 2009 between TCLP and R. W. Beck (the "Agreement"). This report has been prepared for the use of TCLP for the specific purposes identified in this report. This report is solely for the information of and assistance to TCLP and should not be relied upon for any other purpose or by any other party unless authorized in writing by R. W. Beck in accordance with the Agreement.

Electric Demand and Capacity Resources

In July 2009, R. W. Beck prepared an econometric load forecast for TCLP for the period 2009 through 2028, which reflects a "business-as-usual" growth trend and an adjusted load forecast to account for the implementation of an Energy Optimization

Plan ("EOP") as required under Michigan Public Act 295. The adjusted load forecast projects the peak demand to grow to approximately 83.5 MW by 2028. Table ES-1 below shows a summary of TCLP's forecast after accounting for the impact of the EOP.

Table ES-1
TCLP Load Forecast After EOP Impacts

	Fiscal Year Energy		Calendar Year Peak Demand		
	(MWH)	% Change	(MW)	% Change	Load Factor
2009	347,786		74.6 [1]		53.2%
2010	349,887	0.6%	74.9	0.4%	53.3%
2011	351,813	0.6%	75.1	0.3%	53.5%
2012	353,373	0.4%	75.1	-0.1%	53.7%
2013	355,363	0.6%	75.5	0.6%	53.7%
2014	364,649	2.6%[2]	77.2	2.2%	53.9%
2015	367,082	0.7%	77.6	0.4%	54.0%
2016	369,711	0.7%	77.7	0.2%	54.3%
2017	372,354	0.7%	78.3	0.7%	54.3%
2018	375,211	0.8%	78.7	0.5%	54.5%
2019	378,189	0.8%	79.1	0.5%	54.6%
2020	381,371	0.8%	79.3	0.3%	54.9%
2021	384,585	0.8%	80.0	0.8%	54.9%
2022	387,993	0.9%	80.5	0.6%	55.1%
2023	391,499	0.9%	81.0	0.6%	55.2%
2024	395,186	0.9%	81.3	0.4%	55.5%
2025	398,971	1.0%	82.0	0.9%	55.5%
2026	402,929	1.0%	82.6	0.7%	55.7%
2027	406,889	1.0%	83.1	0.7%	55.9%
2028	411,023	1.0%	83.5	0.4%	56.2%

[1] The actual peak demand for 2009 was 67 MW.

[2] It has been assumed that TCLP will gain a significant number of customers from Consumers Energy beginning 2014.

TCLP has ownership shares in two coal-fired power plants, Belle River, operated by Detroit Edison, and Campbell 3, operated by Consumers Energy, and a combustion turbine unit, operated by Michigan Public Power Agency ("MPPA"), and owns and operates a wind turbine located in its service area. The combined dependable operating capacity of the TCLP generating facilities is approximately 58.4 MW. TCLP's current generating resources are described in more detail in Table ES-2 below.

Table ES-2
Summary of TCLP Generation Resources

Unit	Technology	Fuel	Net Capacity MW	In-Service Year
Belle River	ST	Coal	10.5	1983
Campbell Unit 3	ST	Coal	10.4	1980
Kalkaska CT	CT	Natural Gas	36.9	2003
Traverse Wind	Wind	N/A	0.6	1996
Total			58.4	

TCLP is also a member of MPPA and a member of MPPA's power pool, which provides access to excess energy and supplemental energy needs of several other MPPA municipal members from which to buy supplemental power and sell excess power. Transactions among the power pool members are based on a purchase power contract with MPPA, which will expire December 31, 2010.

In order to meet TCLP's projected additional need for capacity and renewable energy resources, it has recently entered into a 20-year Power Purchase Agreement ("PPA") for 10 MW of wind energy from Heritage Stoney Corners Wind Farm I, LLC ("Heritage Wind"), which will increase TCLP's renewable energy portfolio. It is also planning to enter into a PPA for approximately 2 MW of landfill gas from Granger Electric of Michigan, LLC ("Granger Landfill Gas") as a member of MPPA.

Figure ES-1 below illustrates TCLP's projected demand and capacity requirements based on the load forecast, existing resources, new PPAs and a 15% reserve margin over the Study Period. As shown below, even with the new PPAs acquired during 2009, TCLP will experience a capacity shortfall beginning 2011 without additional generating resources. TCLP current plans are to fill the shortfall over the period 2011 through 2014 through short-term purchases until additional generation can be installed or acquired. Note that the wind capacity, including the Heritage Wind PPA, is counted at only 8.0% of its installed capacity. This adjustment is based on a MISO standard and is intended to reflect the fact that wind units are not dispatchable and typically operate at less than their rated capacity during summer peak periods. As a result, the Heritage Wind PPA and TCLP's existing 0.6 MW wind unit are discounted to 0.8 MW and 0.05 MW, respectively.

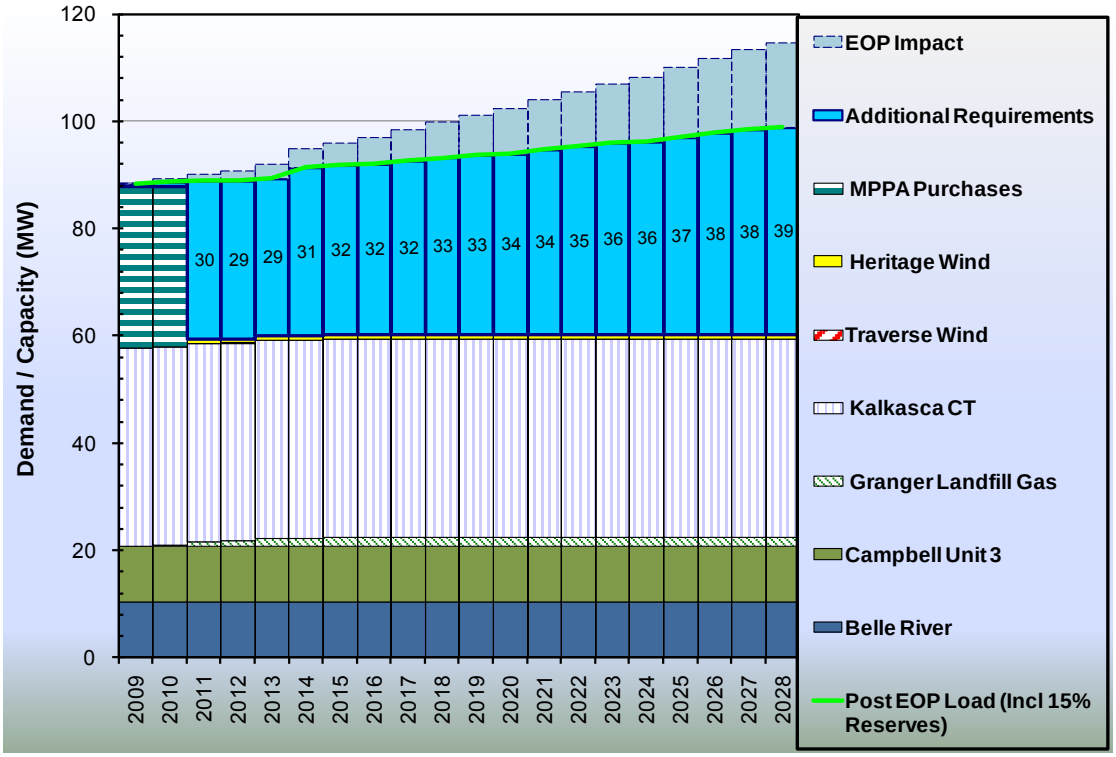

Figure ES-1: Traverse City Light and Power Capacity and Demand Summary

In order to meet the capacity and energy requirements in 2015, it is imperative to have a resource plan and strategy to implement the development, construction and commissioning of the next increment of generation. The additional generation resource(s) should be consistent with TCLP goals and comply with the Michigan renewable energy standards.

Fuel Mix

Preserving fuel diversity in power generation and balancing the risks associated with future fuel prices and price volatility are key principles of TCLP's strategic plan. To reduce risk and provide for continued flexibility, it is a goal of TCLP that its generation be powered by a variety of fuels, including natural gas, coal and a range of renewable sources. Figure ES-2 illustrates TCLP's current capacity fuel mix based on owned and contracted capacity in 2010 (with wind resources shown at nameplate capacity).

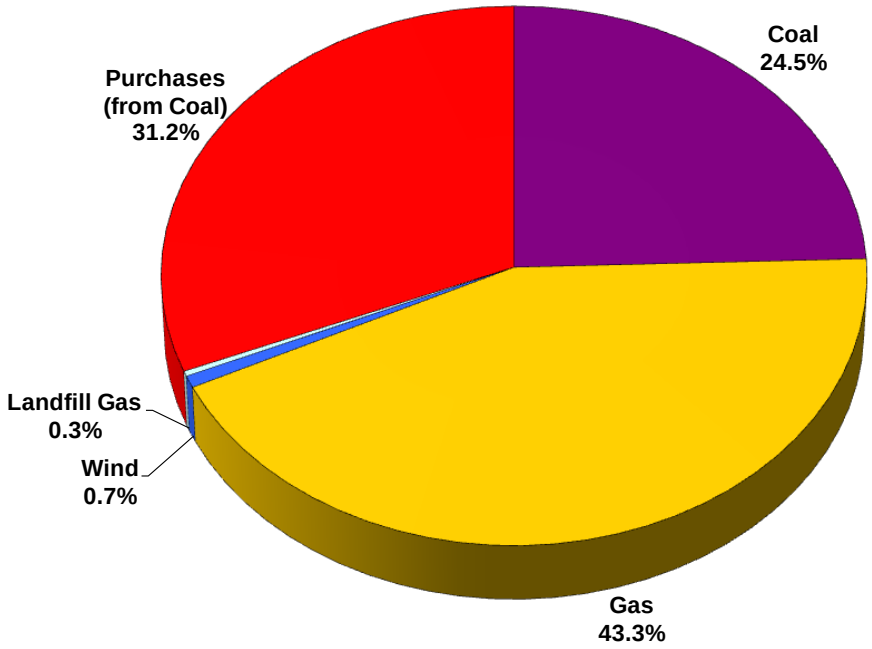

Figure ES-2: Traverse City Light and Power Capacity Fuel Mix in 2010

As the chart shows, coal currently represents more than one-half of the current fuel mix based on capacity and, given its typically high capacity factor, is a key contributor to lower overall fuel costs and reduced price volatility for customers. However, gas is also an important contributor to the diversity of the portfolio.

Figure ES-3 shows the projected capacity fuel mix as of 2015 under a resource portfolio option that is identified later, in the results discussion, as a potential optimal resource mix, including the existing coal, gas, and renewables capacity, along with additional gas-fired combustion turbine and biomass capacity. Additional potential optimal resource portfolios discussed later include larger amounts of biomass capacity.

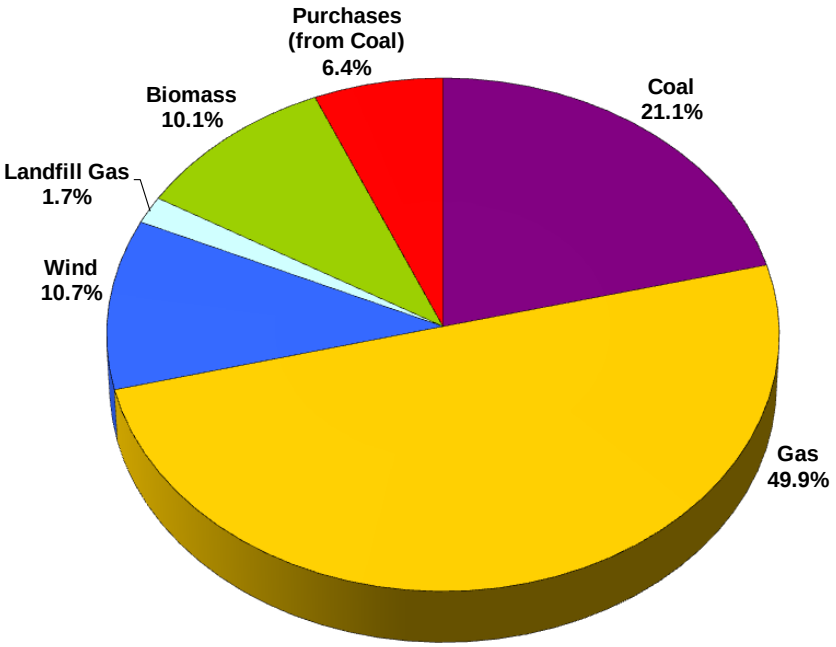

Figure ES-3: Traverse City Light and Power Capacity Fuel Mix in 2015

As illustrated in Figure ES-3, the 2015 fuel mix is fairly different from 2010, with the capacity contribution of renewables increasing to approximately 23% from 1%, of gas increasing to approximately 50% from 43%, and coal decreasing to approximately 28% from 56%. Importantly, the coal and biomass resources can be expected to operate at much higher capacity factors than the gas resources, such that the fuel mix on an energy basis would be much more weighted to those resources. The 2015 fuel mix increases the diversity of the overall portfolio principally from additional renewable sources, while retaining the benefits of fossil fuel diversity by continuing to include significant natural gas and coal contributions. The portfolio also retains some flexibility associated with short-term purchases.

IRP Process

R. W. Beck's process in developing a successful integrated resource plan includes the following:

- Development of a load forecast that reflects TCLP's Energy Optimization Plan ("EOP")
- Identification of viable generating resource options and development of the costs and operating characteristics of each option that meet the goals and standards set by TCLP
- Projections of fuel costs and power prices in the Michigan region

- Busbar[1] screening analyses of the generation options
- Development of the optimal resource plan(s) that take into account costs and risks of all alternatives and combinations of alternatives

Prior to performing the resource expansion optimization analysis, all generating resource alternatives evaluated for the IRP Study were assessed for their levelized cost (or average present value costs) over a consistent study period and operation relative to all other alternatives, a process frequently referred to as a busbar screening analysis.

Following the busbar screening analyses, the generating resource alternatives that were identified as reasonable candidates for further evaluation were combined in a resource expansion optimization model to identify an optimum resource expansion plan. The model used by R. W. Beck incorporates an algorithm that couples a rigorous dynamic programming optimization process with a stochastic[2] representation of uncertain future conditions for load, fuel prices, carbon dioxide ("CO_2") prices, and power prices. The model thus produces a least-cost resource plan (at a given risk tolerance) by simulating the real option cost and value of resource expansion decision-making that occurs in actual utility practice.

Economic and financing assumptions, load forecast, fuel prices, emission allowance prices, generating resource characteristics and costs, and other general assumptions used to perform the generation expansion analysis are set forth in Section 2 of the Report and are summarized under the section entitled 'Principal Considerations and Assumptions' near the end of the Executive Summary.

Busbar Screening Analysis Results

Generating resources are compared on a total average present value dollars per MWh basis over a range of capacity factors considered reasonable for the type of resource being evaluated. When a generating resource alternative is found to be lower cost than all, or many, other alternatives in a particular class of resources, the alternative would be retained for further investigation. Experience demonstrates that alternatives that possess the lowest average total production cost within a given operating range (capacity factor) using a busbar screening approach will likely also be identified as the principal alternatives selected through a more rigorous dynamic optimization analysis. The detailed results of the busbar screening analysis are set forth in Section 3 of this Report.

Figure ES-4 below provides a summary of the present value average costs, in 2008 dollars, over the period 2011 through 2028 of the resources included in the busbar screening analysis over a range of capacity factors.

[1] The busbar screening analyses only include capital and operating costs of each resource alternative, but do not include the cost of transmission. The cost of transmission was assumed to be generally comparable for the evaluated resource alternatives.

[2] Stochastic projections reflect the uncertainty and volatility in forecasting variables such as fuel costs and electric loads. A stochastic projection is usually captured by forecasting future values based on past economic behavior and numerous future outcomes. The resulting stochastic projection provides a range of potential values instead of one forecasted value.

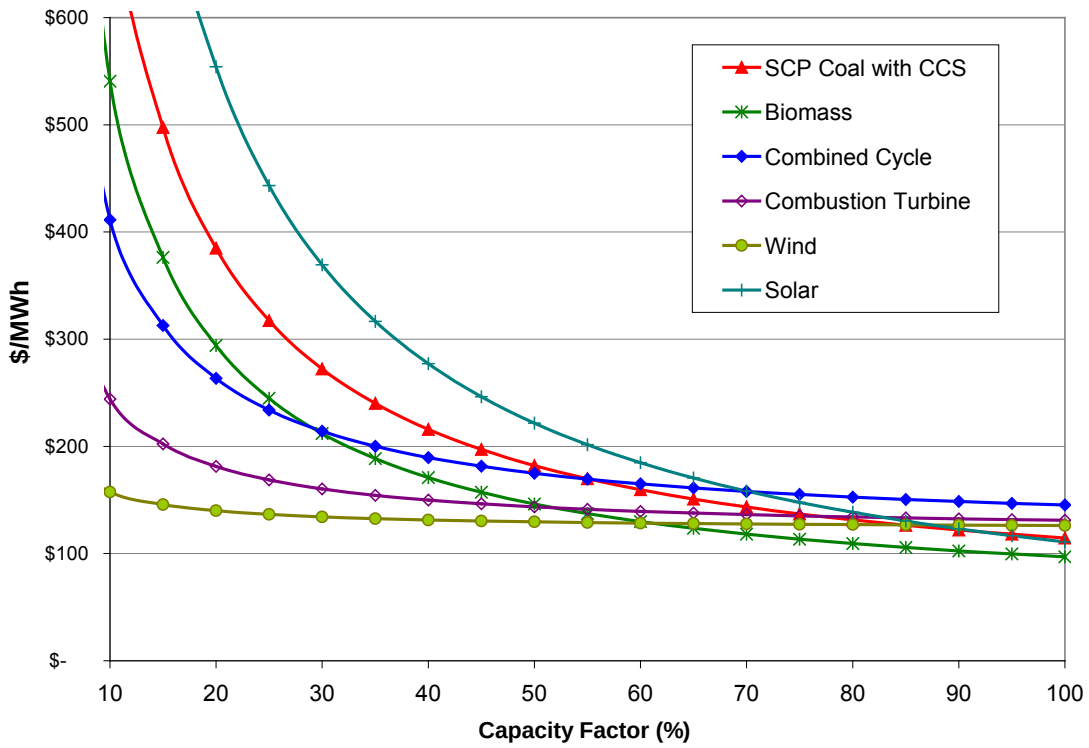

Figure ES-4: Average Levelized Cost v. Capacity Factor

The results of the screening analysis suggest that the Heritage Wind PPA is the lowest cost resource at low capacity factors and that the Biomass unit is the lowest cost resource at high capacity factors. Given the high capital cost of the solar photovoltaic resource, this resource has a higher energy cost throughout most of the capacity factor range. The points of intersection between any two-cost curves suggest a break-even between the two resources in question, beyond which the lower cost resource would be preferred. For example, the combined cycle and supercritical pulverized ("SCP") coal with carbon capture and sequestration ("CCS") resource intersect near 55% capacity factor. Beyond this point, the coal resource is able to spread the greater capital cost over more hours and achieve lower cost than the combined cycle resource.

However, it is important to consider the capacity factors over which the resource in question would typically operate. It also must be recognized that this simplified analysis does not take into account the benefit of dispatchability, meaning the ability to dispatch the unit when it is most advantageous. For example, the wind and solar resources are unlikely to achieve capacity factors beyond 30% and 50%, respectively. Therefore, the solar resource is clearly not economic in the majority of situations, at the estimated capital cost. In addition, considering that the wind resource will only generate electricity when the wind is blowing, it is unable to be reliably dispatched at the times of the highest load and highest market prices. Therefore, despite the appearance of lower average cost, the wind resource is more than likely inferior to the combustion turbine resource, from a pure economic perspective.

Generation Resource Expansion Results

R. W. Beck utilized a proprietary dispatch simulation and dynamic resource optimization model to simulate the addition and dispatch of TCLP's existing resources and all possible combinations of varying amounts of each resource type, in some cases, up to certain limits. The resource optimization algorithm determines when and in what order resources should be added to minimize total power costs, given the uncertainty in future conditions over the Study Period. The "Optimal Resource Expansion Plan" is the generating resource plan that produces the lowest present value of total expected power supply costs and within a given risk tolerance.

Given uncertainty with respect to the opportunities, TCLP has or will have to install Biomass capacity locally, the upper limit in the number of Biomass resources that were allowed to be added were varied to create the following potential Optimal Plans.

- Case 1: 10 MW (a single unit) of the Biomass resource option
- Case 2: 20 MW (two units) of Biomass
- Case 3: 30 MW (three units) of Biomass

Optimal Resource Plan

Case 1 Results - Figure ES-5 depicts the optimal resource expansion plan for TCLP based on the assumptions described in Section 2 and the consideration of only one Biomass unit. The analysis suggests an expansion plan with TCLP's existing resources, including the 10 MW of the Heritage Wind PPA, the full 10 MW of available Biomass capacity, brought online in 2015 (the first year available), and approximately 13 MW of Combustion Turbine capacity, also brought online in 2015.

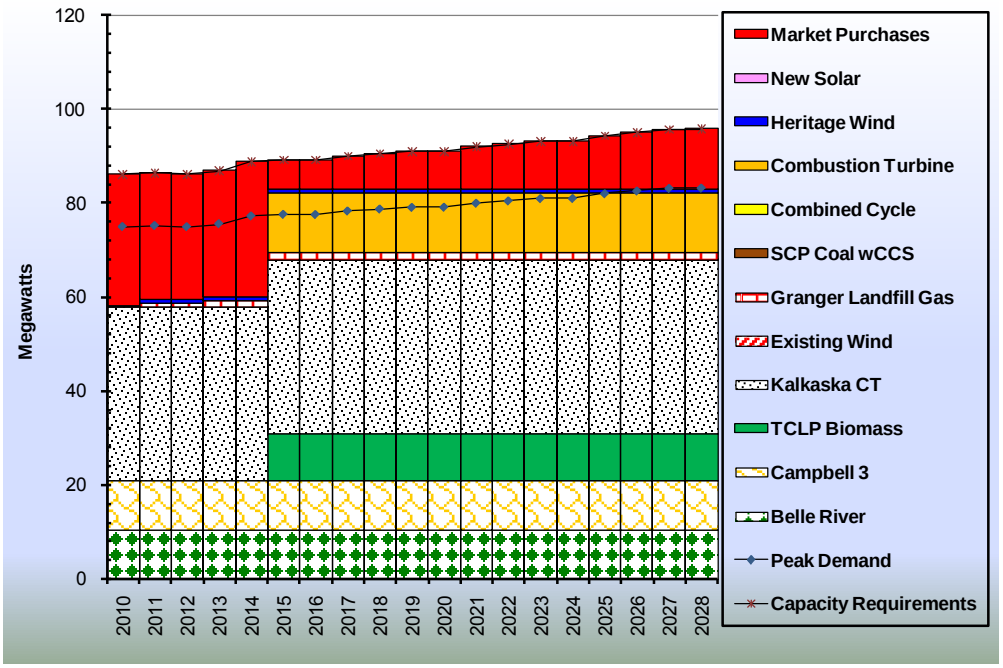

Figure ES-5: Optimal Plan – Case 1

Figure ES-6 below depicts the range of projected annual average power costs under the Case 1 Optimal Plan. The lines shown include the expected value, or mean, across the draws and the 5th and 95th percentiles, encompassing 90 percent of the potential power costs. In the upper left corner of the graph is shown the levelized power costs over the Study Period and the standard deviation, across the draws.

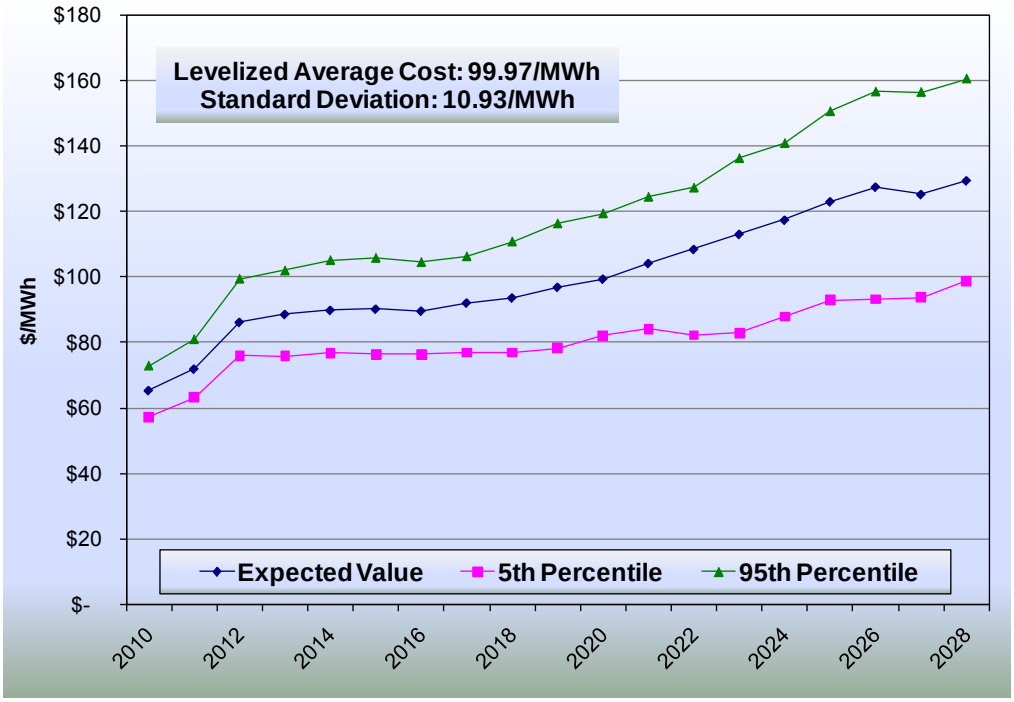

Figure ES-6: Range of Power Supply Costs – Case 1

Case 2 Results - Similarly, Figures ES-7 and ES-8 below depict the optimal resource expansion plan for TCLP, based on the consideration of up to two Biomass units, and the resulting range of projected annual average power costs, along with the levelized cost and standard deviation across the draws. Similar to the Case 1 results, the full amount of available Biomass capacity (20 MW) is brought online in the first available year. Most of the remaining capacity needs are fulfilled through the addition of approximately 6.3 MW of combustion turbine capacity.

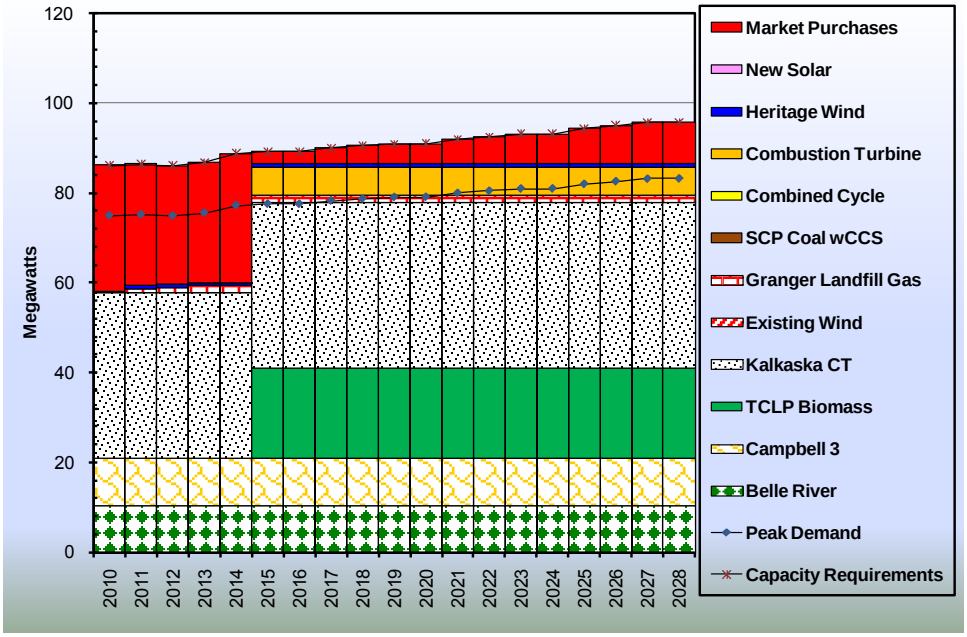

Figure ES-7: Optimal Plan – Case 2

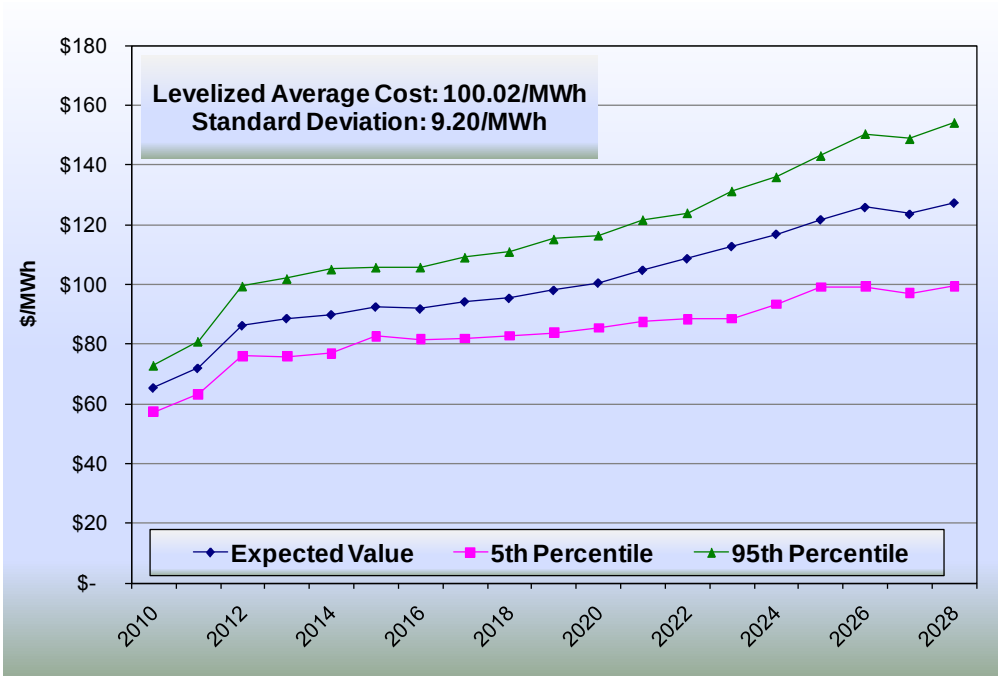

Figure ES-8: Range of Power Supply Costs – Case 2

Case 3 Results - Finally, Figures ES-9 and ES-10 below depict the optimal resource expansion plan and the resulting range of projected annual average power costs for Case 3. Similar to the results for Cases 1 and 2, the upper limit of 30 MW of Biomass capacity is selected for installation, the first two units of 10 MW each in 2015 and the third unit in 2016 or thereafter. This amount of capacity, combined with TCLP's existing resources meets nearly all of TCLP's capacity needs over the Study Period, with the rest being fulfilled with short-term capacity purchases.

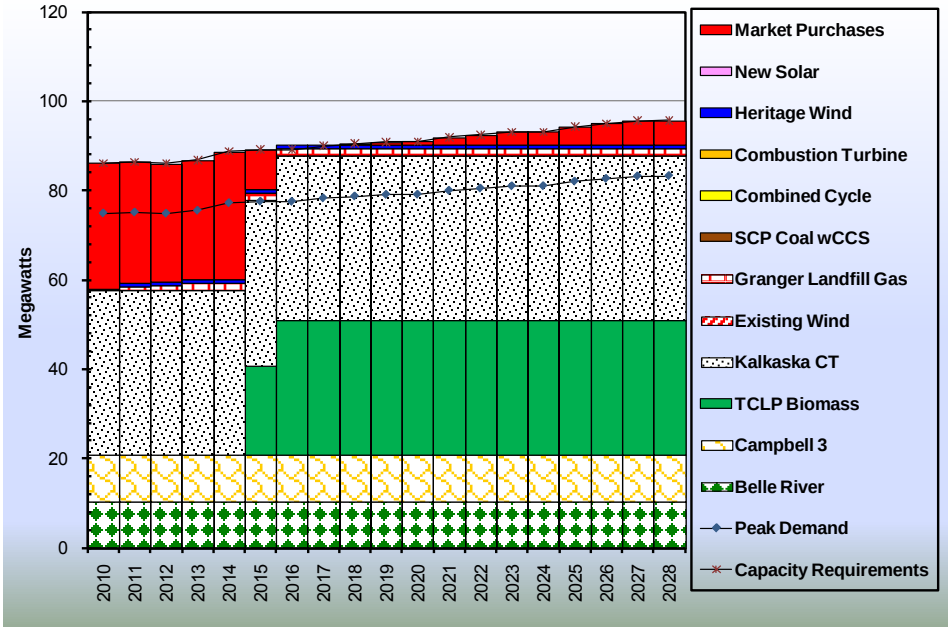

Figure ES-9: Optimal Plan – Case 3

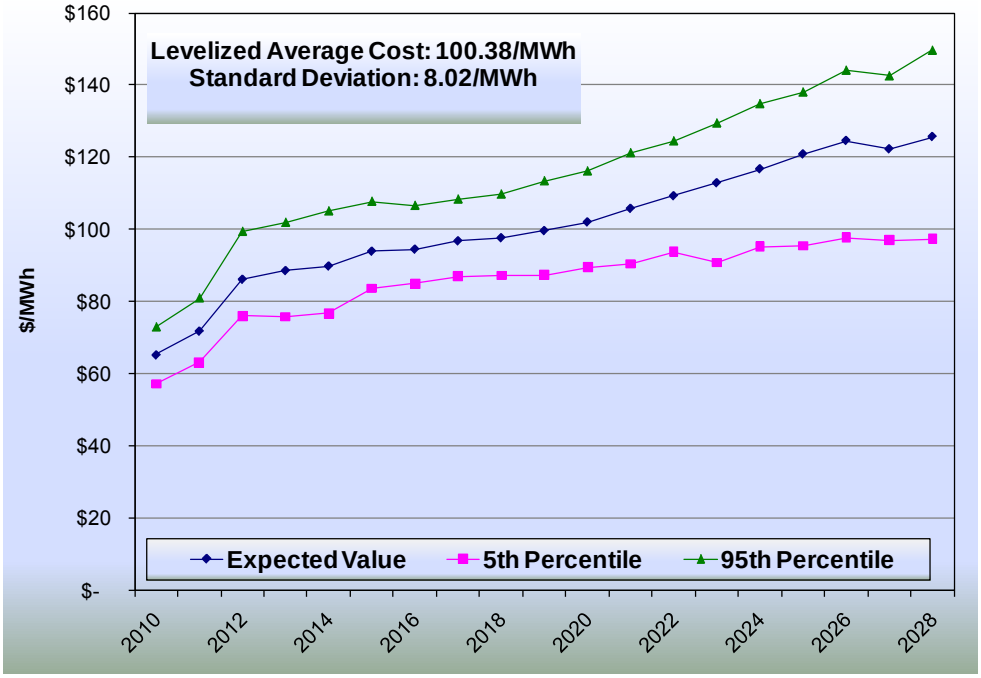

Figure ES-10: Range of Power Supply Costs – Case 3

Sensitivity of Results to Natural Gas Prices

In order to assess the sensitivity of the Optimal Plans to higher and lower natural gas prices, Cases 1 through 3 (again corresponding to varying levels of maximum allowed Biomass capacity) were re-simulated with higher and lower natural gas prices, set to the 70th and 30th percentiles, respectively. The resulting gas prices correspond to levels at which gas prices are only 30% likely to be higher or lower, respectively. Under the High Gas Prices sensitivity case, gas prices are on average approximately 27% higher than the expected gas prices. Under the Low Gas Prices sensitivity case, gas prices are on average approximately 21% lower than the expected prices.

The results of this scenario showed that the Optimal Plans in each case were essentially unaffected by the High Gas Prices sensitivity. This is primarily because the Optimal Plans already resulted in essentially the maximum amount of Biomass capacity possible being selected. The Combustion Turbine capacity selected in Cases 1 and 2 were also unaffected, as the market is similarly influenced by natural gas prices as the operating costs of this technology. However, the resulting market prices are still not high enough to warrant the higher capital costs of building the SCP Coal with CCS resource or additional renewable resources.

The Low Gas Prices sensitivity, on the other hand, resulted in Optimal Plans reflecting significant delays in the build-out of Biomass capacity. However, the ultimate amount of Biomass capacity that was reflected in the Optimal Plan was the same. Figure ES-11 provides an example, using the results of Case 2, which corresponds to a maximum allowed Biomass capacity of 20 MW. As compared to the results under expected gas prices, shown in Figure ES-7, the Optimal Plan under this sensitivity reflects only 10 MW of Biomass capacity added in 2015, with the remaining allowed 10 MW not built until 2026. The 6.3 MW of Combustion Turbine capacity is also added in 2015, as in the expected case. The Low Gas Prices sensitivity also reflects the market being relied upon for a greater share of capacity and energy needs.

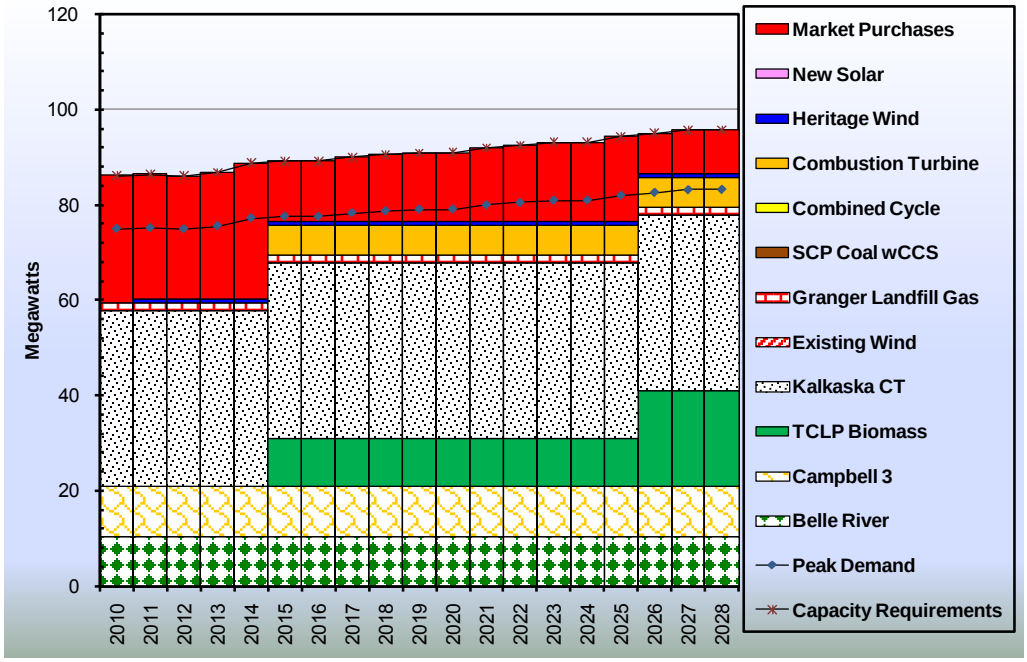

Figure ES-11: Optimal Plan – Case 2 (Low Gas Prices Sensitivity)

Costs versus Risks

Figure ES-12 below provides a comparison of the three alternative Optimal Expansion Plans versus the Base Plan in the form of an X-Y chart, which combines both the levelized power cost over 2011-2028 for each plan and its standard deviation. The relative position of each plan along the X- and Y-axes corresponds to a trade-off between a preference for lower expected costs and a preference for projected costs of greater certainty (i.e., lower standard deviation), with points closer to the origin being overall more preferred. It is up to the utility planner to determine the acceptable trade-off between resource plans of lower cost versus those of lower uncertainty.

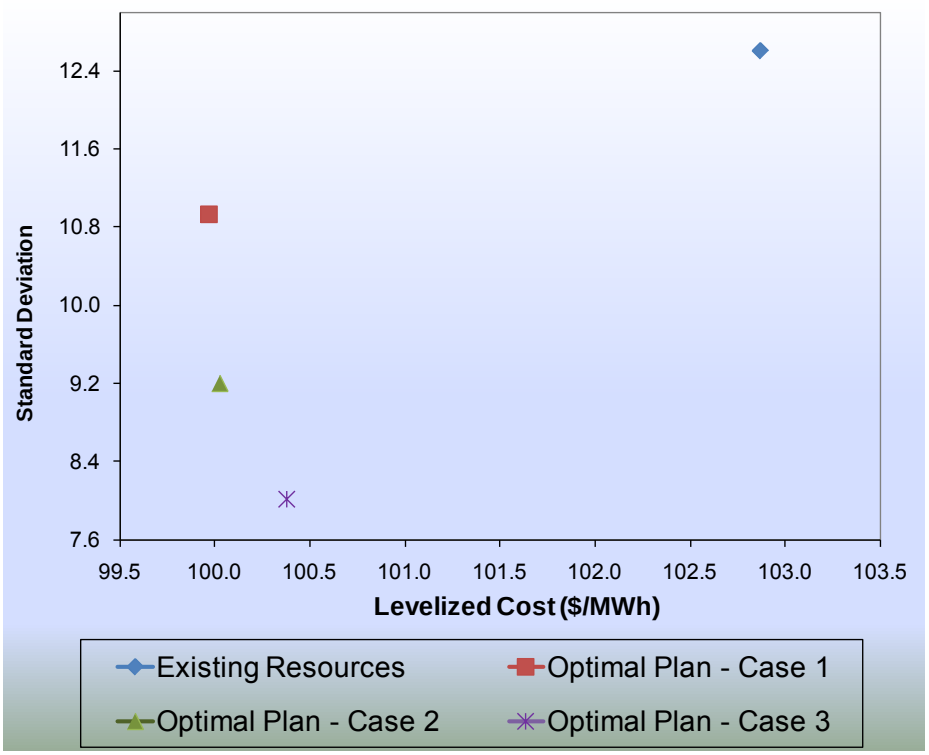

Figure ES-12: Power Supply Costs Comparison

The results reflect that the Optimal Plans result in lower average levelized cost than the Existing Resources, and that they also successively lower the standard deviation of levelized power costs across the draws. The Optimal Plans add a significant amount of Biomass capacity, which both lowers the average levelized cost and significantly lowers the variability in levelized cost, which is evident in the lower standard deviation. This is most likely driven from the fact that the Biomass resource utilizes fuel that is subject to less volatility than gas-fired resources, based on the assumptions relied on herein, which also influence market prices more so than other fuel types.

The overall results discussed above suggest that, given the resource options that have been considered and the assumptions discussed in Section 2, TCLP is projected to achieve lower cost and greater certainty of cost with as much as 20-30 MW of Biomass capacity to be brought online over 2015-2026. These units are intended to operate at high capacity factors, and indeed must be to support steam or hot water sales to which they would be tied. Given that amount of capacity and TCLP's other resources, it is estimated that as much as 40% of the energy generated by this amount of Biomass capacity would be surplus to be sold into the wholesale market for the first several years of the Study Period. While the risks associated with this surplus energy are accounted for in the simulations that support the additions of Biomass capacity, TCLP should consider its tolerance for risk and perhaps limit its exposure somewhat. Accordingly, the Case 2 results, which consist of the additions of 20 MW of Biomass capacity and approximately 6.3 MW of Combustion Turbine capacity appear most reasonable and representative of balancing TCLP's goal of lowest cost and minimizing risk. Given the results of the Low Gas Prices sensitivity, TCLP might consider

building a smaller amount of Biomass capacity in the 2015 timeframe and building additional capacity somewhat later. This would afford TCLP some flexibility in the event that the relatively low natural gas prices that are evident today appear likely to be sustained in the long-term.

REP Results

Figure ES-13 below provides a graphical representation of the projected amount of renewable generation in TCLP's portfolio as compared to the REP goal outlined in Michigan Public Act 295. The chart shows that the Existing resources, with the Heritage PPA are projected to be well above the state requirements through 2014 and exactly meet the current State REP Goal for 2015 and beyond. The additions of significant amounts of Biomass capacity reflected in the Optimal Plans result in renewable generation that far exceed the State REP requirements, as well as TCLP's RPS Goal, over the Study Period.

The State REP Goal shown below is intended to represent how that legislation will be interpreted for purposes of tracking TCLP's renewable requirements. The growth in the renewable percentage through 2015 is based directly on the percentages outlined in the legislation, while the percentages beyond 2015 are based on the amount of renewables required in 2015 applied to the forecasted energy requirements, net of the EOP, over the forecast horizon. This results in a slightly declining required share of renewable generation, as TCLP's energy requirements are forecasted to grow by 0.9% per year over 2010-2028.

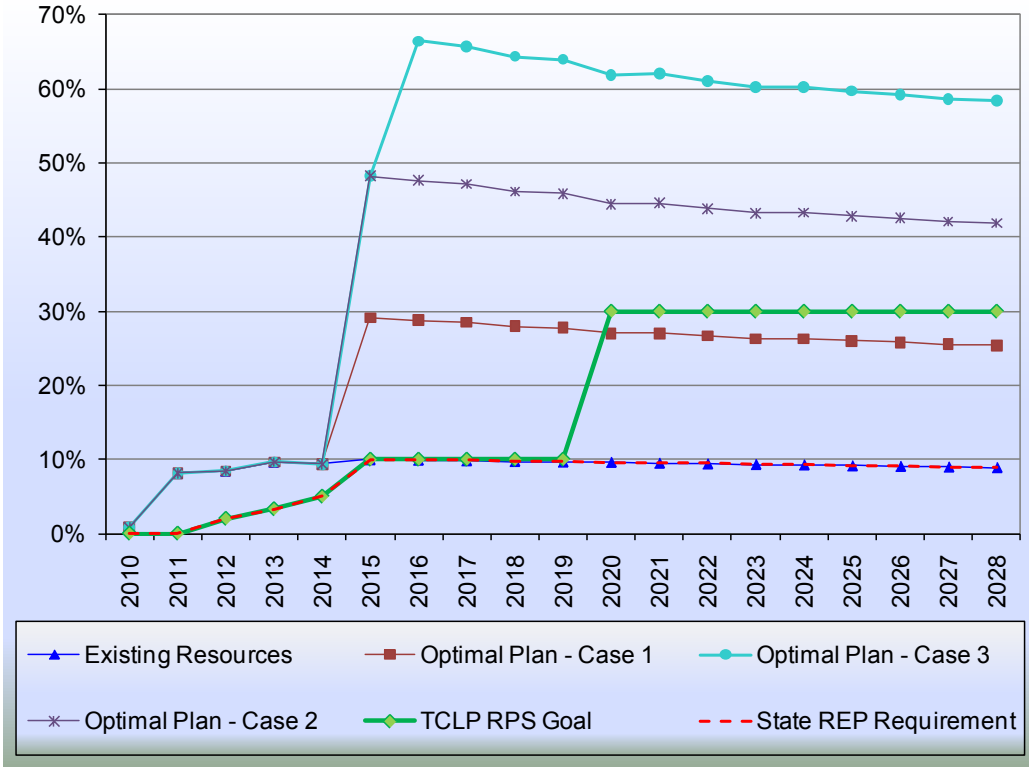

Figure ES-13: Renewable Generation v. Michigan REP Goal

Principal Considerations and Assumptions

In the preparation of this report and the opinions, which follow, we have made certain assumptions with respect to conditions that may occur in the future. TCLP has also made certain assumptions with respect to its projections of future operations. We have used and relied upon certain information and assumptions provided by TCLP, as well as certain information and assumptions provided to TCLP by others. To the extent that actual future conditions differ from those assumed herein, the actual results will vary from those forecast. The principal considerations and assumptions made in preparing this report that were made by us or provided to us by TCLP or others are set forth in Section 2 of the Report and the key assumptions are summarized below.

The generation resource options considered in the IRP include the following:

- Supercritical pulverized coal-fired steam plant with CCS (SCP Coal with CCS) – 8.5 MW
- Combined cycle gas turbine (SOLAR[3] Model T70-CC1 with combined heat and power 'CHP' operation) – 8.0 MW
- Simple cycle combustion turbine (SOLAR Model T70-SC1) – 6.3 MW
- Solar Photovoltaic (Solar PV) – 0.1 MW per year (total of 0.5 MW available)
- Wind Heritage PPA (based on Heritage PPA prices) – 10 MW
- Biomass (Gasification configuration with CHP operation) – 10 MW (as defined by TCLP)

For the SCP Coal with CCS resource, it is assumed that TCLP would jointly participate with other municipal or investor-owned utilities in a larger-scale plant totaling 544 MW.

[3] SOLAR – Solar Turbines Incorporated, a subsidiary of Caterpillar Inc., is one of the world's leading manufacturers of industrial gas turbines, with more than 13,400 units and over 1.4 billion operating hours in 96 countries.

Table ES-3 presents the estimated costs and operating characteristics for each of the resource options considered in the IRP Study.

Table ES-3
TCLP New Resource Characteristics

	SCP Coal with CCS [1]	CHP Biomass [2]	Combined Cycle	Combustion Turbine	Heritage Wind [2]	Solar PV [2]
Type			SOLAR Model T70-CG1	SOLAR Model T70-SG1	PPA	
Capacity (MW)	544	10	8	6.2	10	0.1
Fuel	Coal	Biomass	Natural Gas	Natural Gas	Wind	Solar
Earliest In Service Date	2018	2015	2015	2015	2011	2012
Construction Period (months)	72	48	48	36	-	24
Capital Cost (2009$/kW; Incl'd IDC)	$6,774	$4,000	$1,428	$1,291	-	$10,000
Financing Period (years)	40	30	30	30	-	20
Bond Rate for DS %	6.0%	6.0%	6.0%	6.0%	-	6.0%
Fixed O&M (2009$/kW-year)	89.50	95.00	115.00	7.50	-	14.40
Variable O&M (2009$/MWh)	4.80	16.00	4.00	-	105 [3]	0.00
Heat Rate (Btu/kWh)	12,200	8,500	9,623	11,655	-	-
CO_2 Emission Rate (lb/MMBtu)	21	-	120	120	-	-
NO_X Emission Rate (lb/MMBtu)	0.02	0.01	0.01	0.01	-	-
SO_2 Emission Rate (lb/MMBtu)	0.0006	-	0.0006	0.0006	-	-

[1] The capacity rating, O&M costs, and heat rate reflect the impact of parasitic load requirements and additional costs for pumping CO_2 effluent to a permanent storage location and related processing facility loads and costs. It is assumed that TCLP would jointly own this unit with an ownership entitlement of approximately 8.5 MW or multiples thereof.
[2] Data provided by TCLP.
[3] Reflects purchased power agreement price in 2011. Price is escalated at 2%/year thereafter.

Figure ES-10 below depicts the fuel price forecasts for the generating resource options considered.

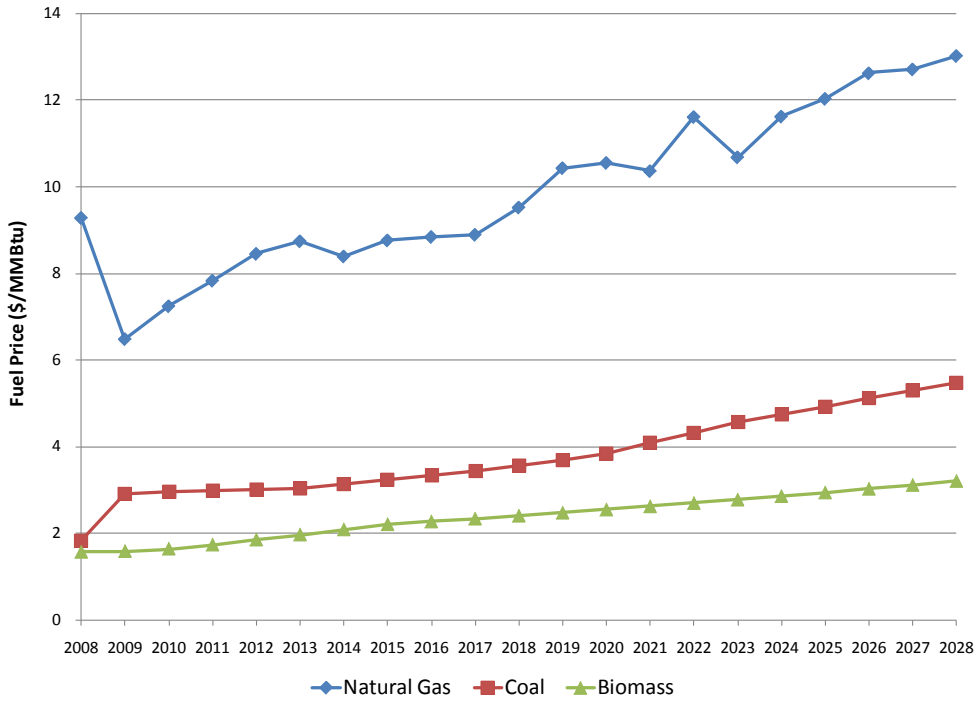

Figure ES-10: Generating Unit Fuel Price Forecasts

Changes or developments in technology, legislation and regulation could affect the considerations and assumptions, and the projections of the electric power and energy requirements of TCLP and the projections of the costs set forth herein. The potential effect of changes or developments in these areas, or potentially other areas that could affect projections, cannot be predicted or determined at this time.

Conclusions

Based on the principal considerations and assumptions set forth in Section 2 of the Report and upon the results of our analyses and studies as summarized in the Report, which Report should be read in its entirety in conjunction with the following, we are of the opinion that:

1. The load forecast (adjusted for TCLP's EOP) prepared in July 2009 results in compound average annual growth rates in peak demand and annual energy requirements of approximately 0.6% and 0.9%, respectively, for the period 2009 through 2028.

2. Taking into consideration the projected peak demand and energy requirements including a 15% reserve margin and the existing capacity resources currently in-service, there is a projected need for additional capacity resources in the amount of 30 MW in 2011 increasing to 32 MW by 2015.

3. The results of the busbar screening analysis indicate that the Biomass option is the lowest cost of the base-load resources (assuming an 85% capacity factor) over the period 2011 through 2028.
4. The results of the busbar screening analysis indicate that the Wind Resource is the lowest cost of the peaking resources (assuming a 25% capacity factor) over the period 2011 through 2028. However, the lack of dispatchability, combined with the typically lower generation during peak summer periods from wind resources, make the unit less economic than the Combustion Turbine resource option.
5. The Optimal Generating Resource Plan, which produces the lowest projected present value of total power supply costs and lowest risk over the Study Period, is an expansion plan with TCLP's existing resources, including the 10 MW of the Heritage Wind PPA, and a build-out of Biomass generation totaling 20-30 MW over the Study Period and 0-13 MW of Combustion Turbine capacity, with larger amounts of Biomass capacity displacing the need for the CT capacity. The amounts of capacity from these two resource types that are most reasonable to be added depend on several factors, including (i) TCLP's tolerance for the risk inherent in the potential for surplus energy generated from the larger amounts of Biomass capacity and (ii) the opportunities and the characteristics of the opportunities that TCLP is able to develop to install this CHP technology on its system.
6. Under the Higher Gas Price sensitivity case, the optimal expansion plans would be unchanged from the Optimal Plans under the Expected Case.
7. The Optimal Generating Resource Plan in Case 2 is projected to exceed the state REP requirements as well as TCLP's REP goals over the Study Period. TCLP's energy from renewable resources under the Optimal Generating Resource Plan Case 2 is projected to be 8.1% in 2011, 48% in 2015, 44% in 2020 and 43% in 2025.

Section 1
INTRODUCTION

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Section 1
INTRODUCTION

1.1 Study Purpose

As a result of the impending termination of a portion of its power supply arrangements, TCLP has initiated a power supply planning process to develop strategies to secure long-term, low-cost power, while meeting certain externally-imposed standards and internal goals regarding renewable resources. TCLP is faced with significant uncertainty in its power supply situation, including load growth uncertainty, fuel and power market price volatility, and uncertainty regarding possible environmental regulations. TCLP must develop a power supply plan that is low-cost, reliable, and capable of mitigating market price volatility, limits the impact of potential greenhouse gas legislation, and meets or exceeds current state and potential future federal renewable portfolio standards.

TCLP is entitled to capacity and energy from two coal-fired generation plants and a combustion turbine plant, through joint ownership arrangements with MPPA and nearby investor-owned utilities, and owns and operates a wind turbine in its service area. TCLP also purchases supplemental wholesale electricity to serve its retail load and sells surplus power through a power pool arrangement operated by MPPA. However, this power pool arrangement is scheduled to terminate at the end of 2010.

TCLP has retained R. W. Beck to conduct an IRP Study using a state-of-the-art stochastic[4] projections approach to:

- Identify possible least-cost power supply plans (at a given risk tolerance) that will meet the future power supply needs of TCLP;
- Assess the potential impact that fuel and power market volatility may have on planning decisions; and
- Assess how pending environmental legislation, chiefly greenhouse gas regulation, may affect power supply planning decisions.

The specific resource options and their costs and operating characteristics are set forth in Section 2.

The information contained in this report, regarding the existing facilities of TCLP, its current and planned operations, availability and cost of fuel supply, and environmental regulations, has been summarized from estimates, data, reports, permits, and records furnished by various sources. TCLP has also provided cost and operating

[4] Stochastic projections reflect the uncertainty and volatility in forecasting variables such as fuel costs and electric loads. A stochastic projection is usually captured by forecasting future values based on past economic behavior and numerous future outcomes. The resulting stochastic projection provides a range of potential values instead of one forecasted value.

characteristics for certain future resource options as noted herein. While R. W. Beck believes such sources to be reliable, it has not verified the accuracy of any information furnished by or obtained from such sources and offers no assurances with respect thereto. To R. W. Beck's knowledge, the summaries presented herein accurately reflect the information obtained from such sources. R. W. Beck has been advised that the information and advice are subject to change based on indeterminate future events that could include material changes in the cost and availability of fuel, in the regulation of environmental matters, in the estimated direct construction cost of electric generating facilities, in the ability of TCLP to finance major capital additions, in the management, ownership and regulation of TCLP and in other costs. Any such adverse changes could likely result in an increase in the projected costs of operating the TCLP electric system.

This study was performed under that certain agreement dated April 20, 2009 between TCLP and R. W. Beck (the "Agreement"). This report has been prepared for the use of TCLP for the specific purposes identified in this report. This report is solely for the information of and assistance to TCLP and should not be relied upon for any other purpose or by any other party unless authorized in writing by R. W. Beck in accordance with the Agreement.

The conclusions, observations, and recommendations contained herein attributed to R. W. Beck constitute the opinions of R. W. Beck. To the extent that statements, information, and opinions provided by TCLP or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate and provides no assurances or warranties to that effect. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report. This report summarizes our work up to the date of this report; changed conditions, which occur or become known after such date could affect the results presented in the report to the extent of such changes.

1.2 Overview of TCLP

TCLP is a municipally-owned entity of the City of Traverse City established in 1912 and governed by an Electric Utility Board. TCLP is responsible for providing power to approximately 11,000 customers within the City's geographic limits and surrounding areas. In 2008, TCLP had a total annual load of approximately 343,000 MWh and summer peak demand of 64.9 MW.

TCLP has ownership shares in two coal-fired power plants—Belle River, operated by Detroit Edison, and Campbell 3, operated by Consumers Energy, an ownership share in a combustion turbine unit operated by MPPA, and owns and operates a wind turbine located in its service area. The combined dependable operating capacity of the TCLP generating facilities is approximately 58.4 MW. TCLP's current generating resources are described in more detail in Table 1-1 below.

Table 1-1
Summary of TCLP Generation Resources

Unit	Technology	Fuel	Net Capacity MW	In-Service Year
Belle River	ST	Coal	10.5	1983
Campbell Unit 3	ST	Coal	10.4	1980
Kalkaska CT	CT	Natural Gas	36.9	2003
Traverse Wind	Wind	N/A	0.6	1996

TCLP is also a member of MPPA and a member of MPPA's power pool, which provides access to excess energy and supplemental energy needs of several other MPPA municipal members from which to buy supplemental power and sell excess power. Transactions among the power pool members are based on a purchase power contract with MPPA, which will expire December 31, 2010. For purposes of this IRP Study, the earliest on-line date of potential resource additions, except future renewable resources is 2011, after the power pool arrangement has terminated.

1.3 Overview of the MISO East Market

For purposes of the IRP Study, the market area in which TCLP resides is referred to as Midwest Independent Transmission System Operator ("MISO") East, encompassing the lower peninsular Michigan, portions of Illinois, Indiana, Missouri, and Ohio. Figure 1-1 and Table 1-2, below, depict the assumed allocation of resources in the modeled MISO East region. The chart and table demonstrate that the region is currently dominated by coal capacity as a base-load resource, has very limited intermediate resources, and relatively small proportion of renewable capacity.

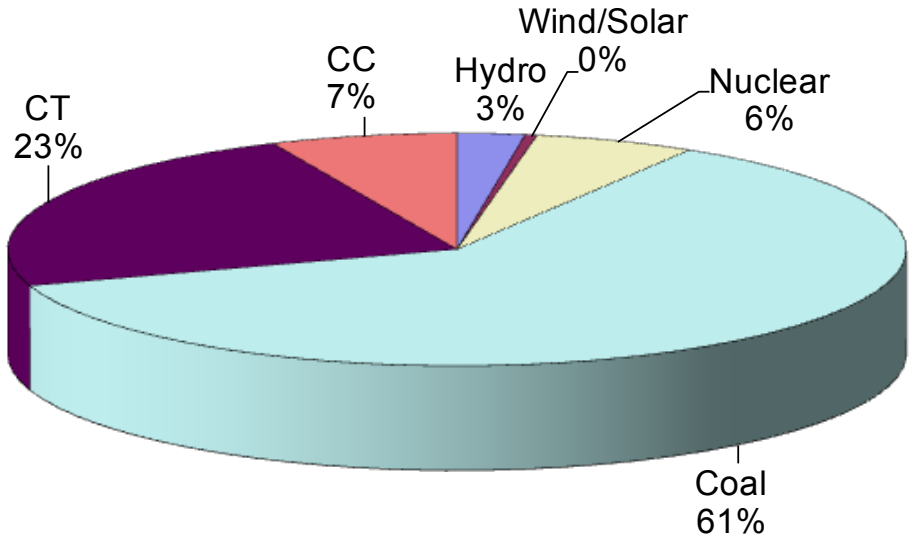

Figure 1-1: MISO East 2008 Resource Capacity Mix

Table 1-2
Regional Resource Capacity Mix in 2008 (MW)

Hydro	2,293
Wind/Solar	405
Nuclear	5,470
Coal	57,715
CT(1)	22,013
CC(2)	6,342
Total Capacity	94,238

(1) Includes all other resources with heat rate greater than 10 MMBtu/MWh
(2) Includes all other resources with heat rate less than 10 MMBtu/MWh

Additional information and modeling assumptions related to the MISO East market are described in Appendix A of this report.

1.4 General Study Approach

R. W. Beck conducted the IRP Study to identify potential least-cost power supply plans for TCLP to meet future load requirements over 2011-2028 and to assess the potential impact that market volatility and future environmental legislation may have on TCLP plans. The steps employed by R. W. Beck included the following.

- Forecast of TCLP service area load, taking into account its Energy Optimization Plan recently developed in response to state legislation.
- Identification of potential new generation resources that TCLP could add beginning in 2011, after the MPPA power pool arrangement is scheduled to

terminate, and an assessment of capital cost, operating costs, and operating characteristics for these resources.

- Forecast of fuel and emission prices for the MISO market area.
- Busbar screening cost analysis of potential generating resource options to rank and identify the best resource alternatives for further consideration and study.
- Analysis and forecast of regional generation expansion and power prices for the MISO East region using a stochastic simulation of fuel prices, power prices, CO_2 allowance prices, hydro generation, and load for use in evaluating potential TCLP generation expansion plans.
- Evaluation of potential least-cost power supply plans for TCLP using a dynamic optimization model and stochastic representation of loads, fuel prices, and CO_2 allowance prices.

The study assumptions, including the results of the load forecast prepared by R. W. Beck in the Spring of 2009, are set forth in Section 2. The methodology and results of the busbar screening cost analysis are set forth in Section 3, and the methodology and results of the generation expansion analysis are set forth in Section 4. Detailed results of the power supply plan results are included in Appendix D. A list of acronyms used herein is set forth in Appendix E.

Section 2
STUDY ASSUMPTIONS

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2.1 System Load Forecast

R. W. Beck has prepared an econometric load forecast for TCLP through 2028, which reflects a "business-as-usual" growth trend, the results of which are shown in Table 2-1 below.

Table 2-1
TCLP Load Forecast - Prior to Energy Optimization Plan (EOP)

	Fiscal Year Energy		Calendar Year Peak Demand		
	(MWh)	% Change	(MW)	% Change	Load Factor
Historical					
2006	347,380	3.0%	72.8	5.8%	54.5%
2007	347,639	0.1%	70.3	-3.4%	56.4%
2008	343,073	-1.3%	64.9	-7.6%	60.3%
Projected					
2009	348,829	1.7%	74.8	15.2%	53.2%
2010	352,668	1.1%	75.5	0.9%	53.3%
2011	357,218	1.3%	76.3	1.1%	53.5%
2012	362,307	1.4%	77.0	0.9%	53.7%
2013	367,871	1.5%	78.2	1.6%	53.7%
2014	380,781	3.5%[5]	80.7	3.1%	53.9%
2015	386,941	1.6%	81.8	1.4%	54.0%
2016	393,402	1.7%	82.7	1.2%	54.3%
2017	399,986	1.7%	84.1	1.7%	54.3%
2018	406,849	1.7%	85.4	1.5%	54.4%
2019	413,898	1.7%	86.7	1.5%	54.5%
2020	421,220	1.8%	87.7	1.2%	54.8%
2021	428,645	1.8%	89.3	1.8%	54.8%
2022	436,336	1.8%	90.7	1.5%	54.9%
2023	444,201	1.8%	92.1	1.5%	55.1%
2024	452,322	1.8%	93.3	1.3%	55.4%
2025	460,621	1.8%	95.0	1.9%	55.4%
2026	469,174	1.9%	96.5	1.6%	55.5%
2027	477,811	1.8%	98.0	1.6%	55.6%
2028	486,708	1.9%	99.3	1.3%	55.9%

[5] It has been assumed that TCLP will gain a significant number of customers from Consumers Energy beginning 2014.

Adjustments to the forecast have been developed to account for the implementation of an Energy Optimization Plan ("EOP") as required under Michigan Public Act 295. Table 2-2 shows the annual incremental reductions in energy sales that are required under the legislation, in terms of the percentage of actual sales, averaged over the preceding three years that are to be reduced through TCLP's energy efficiency programs. Table 2-3 below shows TCLP's forecast after accounting for the impact of the EOP.

Table 2-2
Energy Optimization Plan Standard

Year	Incremental Reduction
2009	0.30%
2010	0.50%
2011	0.75%
2012 and beyond	1.00%

Table 2-3
TCLP Load Forecast After EOP Impacts

	Fiscal Year Energy		Calendar Year Peak Demand		
	(MWH)	% Change	(MW)	% Change	Load Factor
2009	347,786	1.4%	74.6	14.9%	53.2%
2010	349,887	0.6%	74.9	0.4%	53.3%
2011	351,813	0.6%	75.1	0.3%	53.5%
2012	353,373	0.4%	75.1	-0.1%	53.7%
2013	355,363	0.6%	75.5	0.6%	53.7%
2014	364,649	2.6%	77.2	2.2%	53.9%
2015	367,082	0.7%	77.6	0.4%	54.0%
2016	369,711	0.7%	77.7	0.2%	54.3%
2017	372,354	0.7%	78.3	0.7%	54.3%
2018	375,211	0.8%	78.7	0.5%	54.5%
2019	378,189	0.8%	79.1	0.5%	54.6%
2020	381,371	0.8%	79.3	0.3%	54.9%
2021	384,585	0.8%	80.0	0.8%	54.9%
2022	387,993	0.9%	80.5	0.6%	55.1%
2023	391,499	0.9%	81.0	0.6%	55.2%
2024	395,186	0.9%	81.3	0.4%	55.5%
2025	398,971	1.0%	82.0	0.9%	55.5%
2026	402,929	1.0%	82.6	0.7%	55.7%
2027	406,889	1.0%	83.1	0.7%	55.9%
2028	411,023	1.0%	83.5	0.4%	56.2%

A separate report dated July 2009 has been prepared and provided to TCLP, containing a complete discussion regarding methodology, data sources, assumptions, and results of the load forecast.

2.2 TCLP Reserve Capacity Requirements

It is assumed that TCLP must maintain a reserve margin equal to 15%. To the extent that annual capacity resources (existing and future) are not sufficient to meet the 15% reserve criteria, the SERF[6] model will assess a charge equal to $125/kW plus the regional capacity price (as shown in Table A-10 of Appendix A) times the amount of capacity required to meet the reserve criteria. With respect to meeting the reserve margin, MISO limits the capacity credit for wind resources to 8% of wind resource capacity. Therefore, the reliable capacity of wind resources will be derated in the determination of reserve margin. Nevertheless, the full capacity of the wind resources is used for dispatch purposes.

When considering the addition of new capacity resources each year, to the extent annual capacity resources (existing and future) cause the reserve margin to exceed 15%, the SERF model assesses a penalty equal to $150 per kW for capacity exceeding the 15% reserve requirement (the cost of this penalty is not reflected in the projected power supply cost results shown set forth in Section 4 and Appendix D). This assumed penalty tends to limit the addition of resources above the reserve margin, even if the excess capacity would reduce total power costs otherwise.

2.3 TCLP Existing Resource Characteristics

Table 2-4 presents the costs and operating characteristics of TCLP's existing and planned generating resources based on information provided by TCLP.

[6] For the IRP Study, the R. W. Beck proprietary Stochastic Econometric Regional Forecasting ("SERF") model was used. The SERF model generates stochastic projections of fuel prices, electric loads for the region and the subject utility (in this case TCLP), emission prices, and power prices. The model simulates corresponding utility power supply costs for multiple potential resource expansion portfolios based on the stochastic projections. A stochastic dynamic programming algorithm determines the optimal resource expansion decisions. The SERF model is discussed in more detail in Section 4.

Table 2-4
TCLP Existing Resource Characteristics

	Belle River	Campbell Unit 3	Kalkaska CT	Wind Turbine	Granger Landfill Gas
Fuel	Coal	Coal	Natural Gas	N/A	Landfill Gas
Prime Mover	Steam	Steam	CT	Wind	CT
TCLP Capacity (MW)	10.5	10.4	36.9	0.6 [1]	[See Below]
FOM Rate ($/kW-mo; $2008)	3.04	2.78	0.76	1.68	[See Below]
VOM Rate ($/MWh; $2008)	2.16	1.95	5.00	4.03	[See Below]
Average Heat Rate (Btu/kWh)	10,600	9,800	11,000	N/A	[See Below]
NO_X Rate (lb/MMBtu)	0.070	0.070	0.070	N/A	N/A
SO_2 Rate (lb/MMBtu)	0.100	0.100	0.100	N/A	N/A
CO_2 Rate (lb/MMBtu)	210.0	210.0	120.0	N/A	N/A
Forced Outage Rate	4.0%	4.0%	0.0%	N/A	-

[1] It is assumed that wind capacity is equivalent to only 8% of its nameplate for purposes of establishing resource adequacy and reserve requirements.

TCLP is a participant in the planned Granger Landfill Gas project currently under development by MPPA. TCLP has entitlement shares that grow through time, as shown in Table 2-5 below. The energy cost ($/MWh) from the plant is also shown annually below.

Table 2-5
TCLP Granger Landfill Gas Entitlement

Year	Capacity (MW)	Energy Cost ($/MWh)
2009	0.00	77.68
2010	0.26	79.64
2011	0.78	81.63
2012	0.91	83.67
2013	1.43	85.77
2014	1.43	87.92
2015	1.69	90.12
2016	1.69	92.38
2017	1.69	94.69
2018	1.69	97.07
2019	1.69	99.50
2020	1.69	101.99
2021	1.69	104.55
2022	1.69	107.17
2023	1.69	109.85
2024	1.69	112.60
2025	1.69	115.42
2026	1.69	118.32
2027	1.69	121.28
2028	1.69	124.32

Figure 2-1 below illustrates TCLP's projected demand and capacity requirements based on the load forecast and a 15% reserve margin over the Study Period. The chart reflects the addition of the Heritage Wind PPA, which provides TCLP with an entitlement to 10 MW of wind turbine capacity, beginning 2011. Note that both the existing wind unit and the Heritage Wind PPA are counted at only 8.0% of their installed capacity. This adjustment is based on a MISO standard and is intended to reflect the fact that wind units are not dispatchable and typically operate at less than their rated capacity during summer peak periods. As a result, the Heritage Wind PPA and TCLP's existing 0.6 MW wind unit are discounted to 0.8 MW and 0.05 MW, respectively.

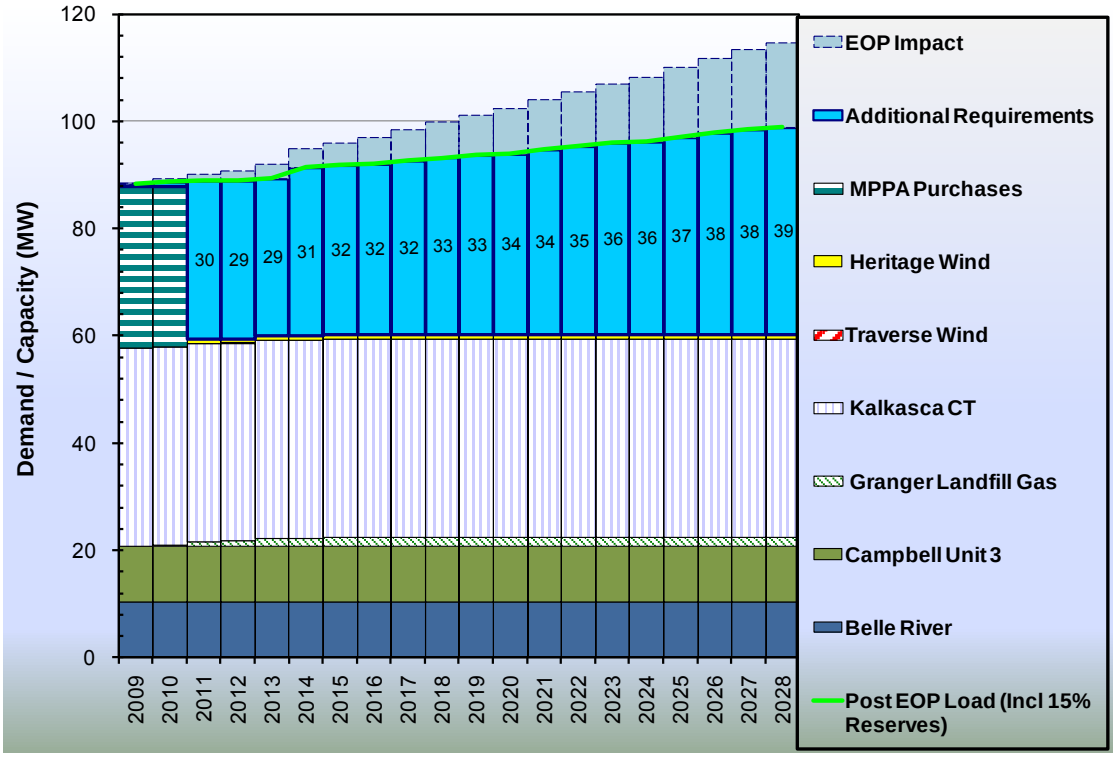

Figure 2-1: Traverse City Light and Power Capacity and Demand Summary

2.4 Existing Debt Service

Table 2-6 below contains TCLP's existing debt service schedule for its generation resources, as provided by TCLP staff. These costs are included in the projected power supply costs shown in Section 4.

Table 2-6
Traverse City Debt Service on MPPA Jointly-owned Units ($000)

Year	Belle River	Campbell 3	Kalkaska CT	Total
2008	1,042	988	1,828	3,858
2009	1,054	806	1,825	3,685
2010	1,054	810	1,825	3,688
2011	1,054	811	1,827	3,692
2012	1,054	811	1,822	3,687
2013	1,054	796	1,822	3,672
2014	1,054	755	1,820	3,629
2015	1,054	715	1,822	3,590
2016	1,054	-	1,818	2,872
2017	1,054	-	1,819	2,872
2018	336	-	1,817	2,153
2019	-	-	1,817	1,817
2020	-	-	1,817	1,817

Year	Belle River	Campbell 3	Kalkaska CT	Total
2021	-	-	1,817	1,817
2022	-	-	1,816	1,816
2023	-	-	1,813	1,813
2024	-	-	1,812	1,812
2025	-	-	1,812	1,812
2026	-	-	1,812	1,812
2027	-	-	-	-
2028	-	-	-	-

2.5 Generation Resource Options

The generation resource options considered in the IRP include the following:

- Supercritical pulverized coal-fired steam plant with CCS (SCP Coal with CCS) – 8.5 MW
- Combined cycle gas turbine (SOLAR[7] Model T70-CC1 with combined heat and power 'CHP' operation) – 8.0 MW
- Simple cycle combustion turbine (SOLAR Model T70-SC1) – 6.3 MW
- Solar Photovoltaic (Solar PV) – 0.1 MW per year (total of 0.5 MW available)
- Wind Heritage PPA – 10 MW increments based on Heritage PPA prices
- Biomass (gasification configuration with CHP operation) – 10 MW (as defined by TCLP)

For the SCP Coal with CCS resource, it is assumed that TCLP would jointly participate with other municipal or investor-owned utilities in a much larger scale plant totaling 544 MW. According to information provided by TCLP, the potential Biomass plant option is a 10 MW gasification configuration combustion turbine that would be operated in combined heat and power (CHP) mode, producing both power and hot water. For analysis purposes herein, we have assumed varying amounts of available Biomass capacity both to address this uncertainty and the uncertainty in the available opportunities that TCLP might have to install this technology on its system.

In order to meet TCLP's projected additional need for capacity and renewable energy resources, it has recently entered into a 20-year Power Purchase Agreement ("PPA") for 10 MW of wind energy from Heritage Stoney Corners Wind Farm I, LLC ("Heritage Wind") which will increase TCLP's renewable energy portfolio. It is also planning to enter into a PPA for approximately 2 MW of landfill gas from Granger Electric of Michigan, LLC as a member of MPPA ("Granger Landfill Gas").

The TCLP renewable resources include the current Traverse Wind unit, the planned Granger Landfill Gas purchase through MPPA and the Heritage Wind PPA.

[7] SOLAR – Solar Turbines Incorporated, a subsidiary of Caterpillar Inc., is one of the world's leading manufacturers of industrial gas turbines, with more than 13,400 units and over 1.4 billion operating hours in 96 countries.

Table 2-7
TCLP Renewable Resource Capacity (MW)

	Traverse Wind	Granger Landfill Gas	Heritage Wind
2009	0.60	0.00	0.00
2010	0.60	0.26	0.00
2011	0.60	0.78	10.00
2012	0.60	0.91	10.00
2013	0.60	1.43	10.00
2014	0.60	1.43	10.00
2015	0.60	1.69	10.00
2016	0.60	1.69	10.00
2017	0.60	1.69	10.00
2018	0.60	1.69	10.00
2019	0.60	1.69	10.00
2020	0.60	1.69	10.00
2021	0.60	1.69	10.00
2022	0.60	1.69	10.00
2023	0.60	1.69	10.00
2024	0.60	1.69	10.00
2025	0.60	1.69	10.00
2026	0.60	1.69	10.00
2027	0.60	1.69	10.00
2028	0.60	1.69	10.00

The existing Traverse Wind unit is modeled using an assumed hourly generation pattern, developed by R. W. Beck, adjusted to a 15% capacity factor, based on the historical capacity factor reported by TCLP. The New Wind resource uses the same pattern, however adjusted to a 24% capacity factor, based on assumptions typically utilized in the MISO region. The Biomass unit is assumed to run at an 85% capacity factor, on a must-run basis. Similarly, the Granger Landfill Gas unit is assumed to run at 100% capacity factor since the arrangement with TCLP is an energy-only purchase.

Table 2-8 presents the associated costs, financing parameters, and operating characteristics for the renewable resources shown above, a solar resource, and potential non-renewable resource options. For the coal-fired resource, it is assumed that TCLP would jointly participate with other municipal or investor-owned utilities. The modeled size of TCLP's entitlement to any of these resources is an outcome of the investment decision analysis embedded in the model, subject to the modeled sizing of "slices" of each resource as discussed in Section 4.

Table 2-8
TCLP New Resource Characteristics

	SCP Coal with CCS [1]	CHP Biomass [2]	Combined Cycle	Combustion Turbine	Heritage Wind [2]	Solar PV [2]
Type			SOLAR Model T70-CG1	SOLAR Model T70-SG1	PPA	
Capacity (MW)	544	10	8	6.2	10	0.1
Fuel	Coal	Biomass	Natural Gas	Natural Gas	Wind	Solar
Earliest In Service Date	2018	2015	2015	2015	2011	2012
Construction Period (months)	72	48	48	36	-	24
Capital Cost (2009$/kW; Incl'd IDC)	$6,774	$4,000	$1,428	$1,291	-	$10,000
Financing Period (years)	40	30	30	30	-	20
Bond Rate for DS %	6.0%	6.0%	6.0%	6.0%	-	6.0%
Fixed O&M (2009$/kW-year)	89.50	95.00	115.00	7.50	-	$14.40
Variable O&M (2009$/MWh)	4.80	16.00	4.00	-	105 [3]	-
Heat Rate (Btu/kWh)	12,200	8,500	9,623	11,655	-	-
CO_2 Emission Rate (lb/MMBtu)	21	-	120	120	-	-
NO_X Emission Rate (lb/MMBtu)	0.02	0.01	0.01	0.01	-	-
SO_2 Emission Rate (lb/MMBtu)	0.0006	-	0.0006	0.0006	-	-

[1] The capacity rating, O&M costs, and heat rate reflect the impact of parasitic load requirements and additional costs for pumping CO_2 effluent to a permanent storage location and related processing facility loads and costs. It is assumed that TCLP would jointly own this unit with an ownership entitlement of approximately 8.5 MW or multiples thereof.
[2] Data provided by TCLP.
[3] Reflects purchased power agreement price in 2011. Price is escalated at 2%/year thereafter.

2.6 Biomass Fuel Price Forecast

To determine a price for biomass fuel, R. W. Beck developed a supply curve representation of the incremental costs of biomass fuel to the delivery point of a proposed generating station within the region surrounding Traverse City. The quantity of biomass feedstock used to develop the supply curve is based on publicly available sources of information in which the existing Biomass supply (dry tons/year) by county in Michigan was provided. The supply curve is based upon the costs of a mix of biomass feedstock (agricultural residues, forest residues, urban waste, switch grass and mill wastes) within 100 miles of Traverse City. While cheaper fuel sources exist beyond this radius, the supply radius was limited to reduce the effects of transportation on the supply curve. R. W. Beck's research suggests that the current area demand for

biomass feedstock for electric generation is between 785 and 800 GWh per year. Based on the supply curve, at this level of demand, the price for biomass fuel is $1.59/MMBtu in $2009.

Table 2-9 below shows the projected price of biomass fuel used throughout the Study Period. Additional information concerning the projection of the cost of biomass is contained in the Biomass Fuel Supply Study included as Appendix B.

Table 2-9
Biomass Price Forecast ($/MMBtu)

2009	$1.59
2010	$1.64
2011	$1.74
2012	$1.85
2013	$1.97
2014	$2.09
2015	$2.21
2016	$2.27
2017	$2.34
2018	$2.41
2019	$2.48
2020	$2.55
2021	$2.62
2022	$2.70
2023	$2.78
2024	$2.86
2025	$2.94
2026	$3.03
2027	$3.12
2028	$3.21

2.7 Gas Price Forecast

R. W. Beck maintains proprietary economic models, to project the market price of natural gas at Henry Hub and 111 market areas throughout North America. Table 2-10 presents R. W. Beck's current natural gas forecast (prepared in early 2009), showing delivered gas prices to an assumed TCLP delivery point relative to Henry Hub and an average of the MISO East region.

Table 2-10
Gas Price Forecast ($/MMBtu)

Year	Henry Hub ($/MMBtu)	TCLP Basis Differential ($/MMBtu)	TCLP ($/MMBtu)	MISO EAST
2009	6.35	0.14	6.49	6.18
2010	7.13	0.12	7.25	6.93
2011	7.73	0.11	7.84	7.50
2012	8.36	0.11	8.46	8.08
2013	8.64	0.10	8.75	8.35
2014	8.30	0.10	8.40	8.02
2015	8.66	0.10	8.77	8.38
2016	8.74	0.11	8.85	8.45
2017	8.77	0.13	8.90	8.49
2018	9.38	0.15	9.53	9.08
2019	10.26	0.17	10.44	9.94
2020	10.36	0.20	10.56	10.04
2021	10.14	0.24	10.37	10.28
2022	11.35	0.27	11.62	10.52
2023	10.38	0.31	10.69	10.76
2024	11.30	0.33	11.63	10.99
2025	11.68	0.36	12.04	11.38
2026	12.24	0.39	12.63	11.94
2027	12.32	0.40	12.72	12.02
2028	12.63	0.40	13.03	12.83

2.8 CO2 Allowance Allocations

The CO_2 emissions allowance costs are generally based on Senate Bill S. 2191, America's Climate Security Act (Lieberman-Warner Bill), as of October 18, 2007. The proposed bill failed to pass the Senate in June 2008. The Lieberman-Warner Bill includes provisions for the regulation of CO_2 and other greenhouse gas emissions in a cap-and-trade system with declining free allowances to limit emissions to the 2005 level beginning 2012, 15% below the 2005 level beginning 2020, and 33% below the 2005 level beginning 2030. The Bill also includes a provision to free allowance allocations to certain entities and provide bonus allowances for carbon capture and storage projects.

On June 26, 2009, the U.S. House of Representatives passed H.R. 2454, the American Clean Energy and Security ("ACES") Act of 2009. ACES is a comprehensive energy bill that includes a cap-and-trade program to reduce national greenhouse gas emissions from capped sources by 17% below 2005 levels by 2020 increasing to 83% below 2005 levels in 2050, a renewable electricity standard applicable to retail electricity suppliers, performance standards for new coal-fueled power plants, and a program to accelerate the commercial availability of CO_2 capture and storage technologies.

If ACES were to be enacted, fossil generating units would become subject to the cap-and-trade program, beginning in 2012. Under the program, each unit must possess emission allowances equal to its annual metric tons of greenhouse gases emitted. Except for merchant coal units and long-term contract generators as defined in the bill and for qualifying CO_2 capture and sequestration projects at electric generating units, no allowances would be allocated to fossil generating units. Allowances would be allocated to electricity local distribution companies for a limited number of years subject to prohibitions related to actual CO_2 emissions and use limitations prescribed by the bill. The renewable electricity standard set forth in ACES applies to retail electric suppliers with annual retail sales of at least four million MWh, which is well above the annual sales level of TCLP.

2.9 TCLP Renewable Generation Goals

Without a federal RPS, adoption and enforcement of an RPS have primarily taken place at the state level. The State of Michigan has codified an RPS in Public Act 295, which establishes the requirement for utilities to develop Renewable Energy Plans ("REP") with specific requirements pertaining to the amount of renewable generation, or credits, to be produced each year.

Table 2-11 shows the Michigan REP requirements that were in place at the time of the study and the RPS goals set forth by TCLP. The REP requirements shown below utilize the projected growth rates of TCLP's system (net of its EOP) and assume that the amount of required renewable generation credits are held constant beginning 2015, per the state legislation and consistent with TCLP's filed REP. Accordingly, the required percentage of renewable generation in any year will gradually decline, as a result of load growth. As the table shows, TCLP has more aggressive goals than the state.

Table 2-11
Summary of Michigan RPS Requirements

	MI REP Requirements	TCLP Goal
2009	0.0%	0.0%
2010	0.0%	0.0%
2011	0.0%	0.0%
2012	2.0%	2.0%
2013	3.3%	3.3%
2014	5.0%	5.0%
2015	10.0%	10.0%
2016	9.9%	14.0%
2017	9.9%	18.0%
2018	9.8%	22.0%
2019	9.7%	26.0%
2020	9.6%	30.0%
2021	9.5%	30.0%

	MI REP Requirements	TCLP Goal
2022	9.5%	30.0%
2023	9.4%	30.0%
2024	9.3%	30.0%
2025	9.2%	30.0%
2026	9.1%	30.0%
2027	9.0%	30.0%
2028	8.9%	30.0%

Figure 2-2 below depicts the projected energy from TCLP's current renewable projects (including the Heritage Wind PPA) as compared to the Michigan RPS requirements. Note that the Michigan REP legislation requires that renewable generation, or renewable credits, equal to 10% of the prior year's energy requirements must be utilized in 2015 to meet TCLP's energy requirements. For each year beyond 2015, the currently required amount of renewable generation is constant.

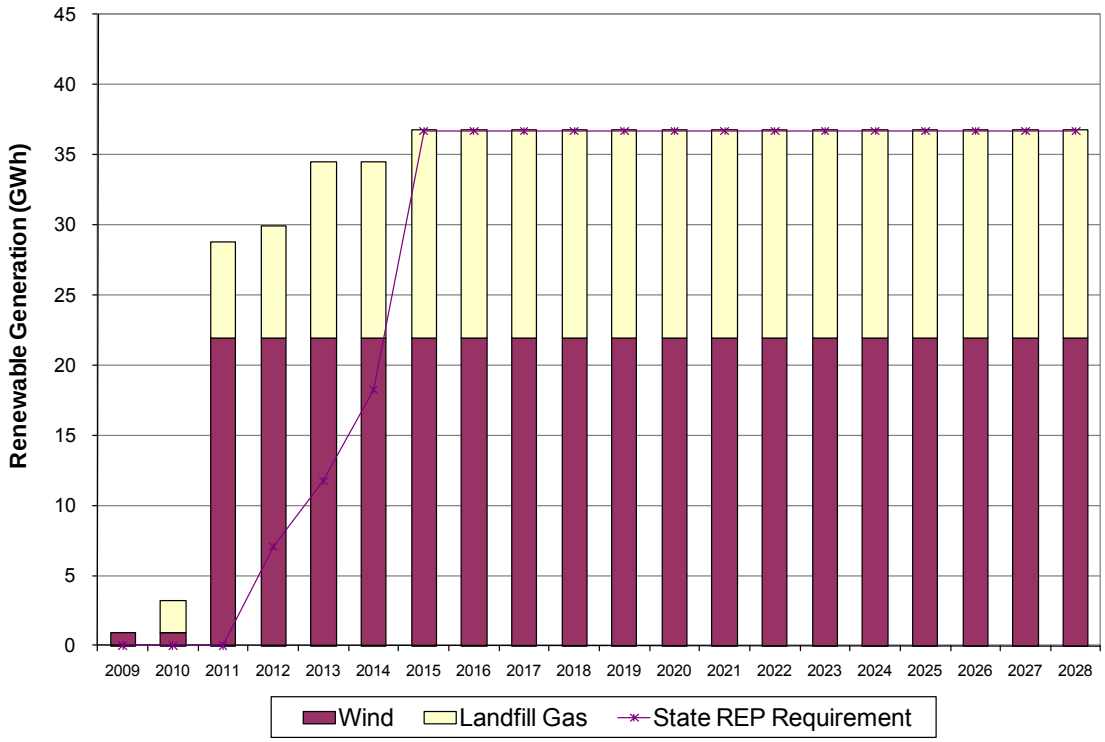

Figure 2-2. TCLP RPS Requirements and Resources

Section 3
BUSBAR SCREENING ANALYSIS

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Section 3
BUSBAR SCREENING ANALYSIS

Prior to performing the resource expansion optimization analysis, all generating resource alternatives evaluated for the IRP Study were assessed for their levelized cost (or average present value costs) over a consistent Study Period relative to all other alternatives, a process frequently referred to as a busbar screening analysis.

3.1 Methodology

Generating resources are compared on a total average present value dollars per MWh basis at particular capacity factors considered reasonable for the type of resource being evaluated. When a generating resource alternative is found to be lower cost than all, or many, other alternatives in a particular class of resources, the alternative would be retained for further investigation. Experience demonstrates that alternatives that possess the lowest average total production cost within a given operating range (capacity factor) using a busbar screening approach will likely also be identified as the principal alternatives selected through a more rigorous dynamic optimization analysis. However, some higher cost resource options might still be retained for further consideration and analysis if the options that were found to be lower cost are known to be limited in the total number that can be installed or in the timing of their installation (e.g., carbon capture and sequestration resources are expected to be unavailable until 2018 at the earliest) or would be needed to meet renewable generation goals, both internal and government-mandated.

For resources for which the operating capacity factor under an economic dispatch in MISO would be unlikely to be attained, replacement power is assumed to be purchased from the MISO market to supplement the unit's operation at a lower capacity factor. Similarly, for resources that are considered not fully dispatchable at their full capacity to meet peak demand, typically assumed to be in the summer (e.g., wind and solar capacity), backstand capacity is assumed to be purchased to supplement the resource capacity available.

The busbar screening analysis was performed using the following major assumptions.

- Resource capital costs, construction spending curve, O&M costs, and operating characteristics as depicted in Section 2, Table 2-8.
- Assumed municipal cost of debt and discount rate as discussed in Section 2, Table 2.8.
- Fuel and emissions price forecasts consistent with those presented in Section 2, Table 2-8.
- Common installation year of 2012, financing and operating period of thirty years, and common present-value discount year of 2009.

- The costs of replacement power and backstand capacity are based on the power market simulation discussed in Appendix A and set forth on Tables A-9 and A-10.

The resulting average costs are compared separately for base-load/intermediate resources and peaking resources. Base-load/intermediate resources include a combined cycle plant, a super-critical pulverized ("SCP") coal plant, both with and without carbon capture and sequestration ("CCS"), and a biomass plant. As discussed further below, the SCP coal option without CCS has been included for comparative purposes only, as this resource type was excluded from the generation expansion analysis discussed in Section 4. Peaking resources include a gas turbine, wind turbine, and a photovoltaic solar generator.

The capital and operating costs and financing assumptions are as discussed in Section 2.5. The base-load/intermediate resources assume an 85% capacity factor. The combined cycle resource would only be expected to operate at a 70% capacity factor, and the analysis reflects additional off-peak market energy to make up the difference between 70% and 85% capacity factors. The peaking resources assume a 25% capacity factor. The combustion turbine is assumed to operate at an 11% capacity factor, and the analysis reflects additional market energy to make up the difference between 11% and 25% capacity factors. In addition, as the wind and solar units are not dispatchable, the capacity of those resources have been derated to 8% and 47%, respectively, and the cost of market capacity to bring the units to full capacity is included and shown in the replacement energy category.

3.2 Results

Figure 3-1 below provides a summary of the present value average costs assuming an 85% capacity factor, in 2009 dollars, over the period 2011 through 2028 of the base-load and intermediate resources included in the busbar screening analysis. As shown below, the projections indicate that the Biomass plant and the SCP Coal resource options are the lowest cost of the base-load resources. However, the current regulatory environment in the State of Michigan has made the development of coal-fired generation very difficult. Accordingly, in consultation with TCLP, R. W. Beck has only considered the coal option *with* CCS in the generation expansion analysis discussed in Section 4.

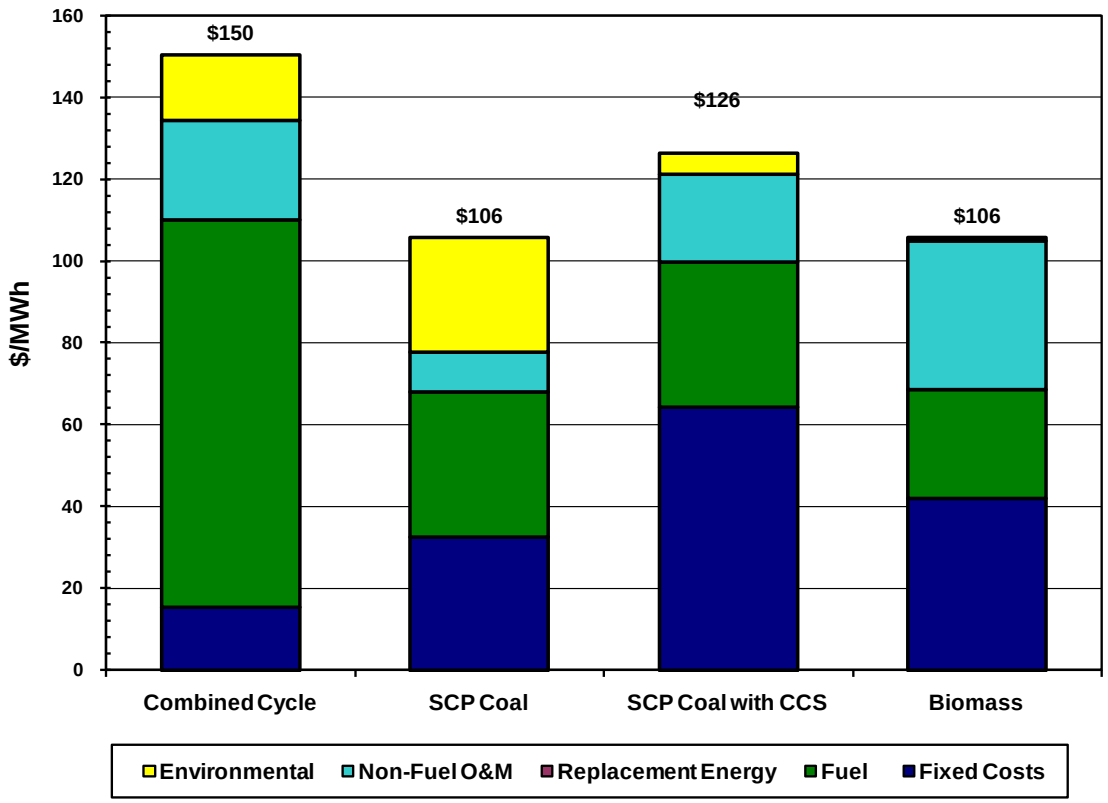

Figure 3-1: Average Present Value Cost of Base-load Resource Options

Figure 3-2 below provides a summary of the present value average costs assuming a 25% capacity factor over the period 2011 through 2028 of the peaking resources included in the busbar screening analysis. As shown below, the Combustion Turbine option is fairly similar in cost to the Heritage Wind resource. The Solar resource is the most expensive of this category and, based on the generation expansion analysis discussed in the next section, is not economic across the majority of scenarios included.

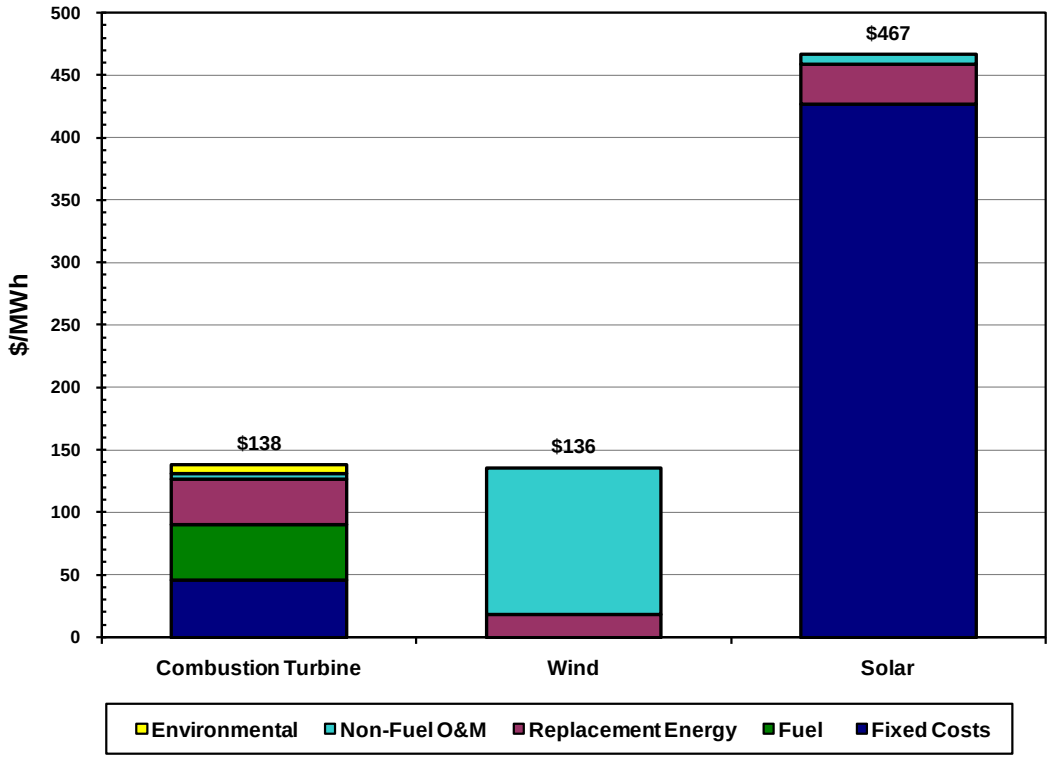

Figure 3-2: Average Present Value Cost of Peaking Resource Options

Figure 3-3 below, shows the net present value costs over the period 2011 through 2028 for all of the resource options over a range of capacity factors.

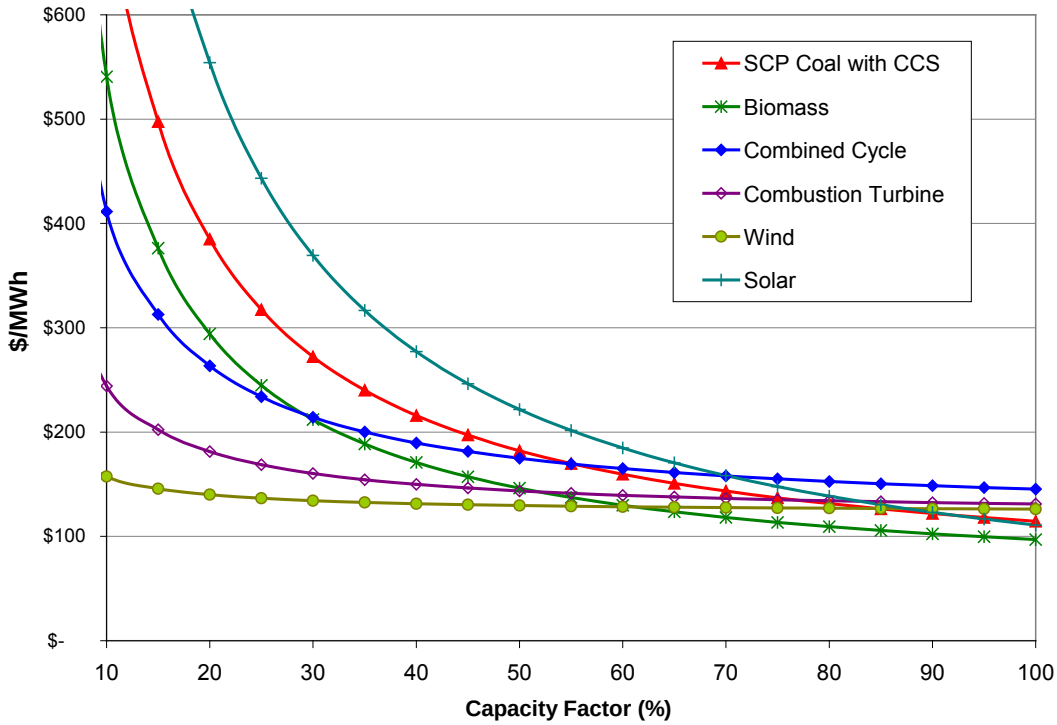

Figure 3-3. Bus Bar Screening Curves of Resource Options

These results, combined with TCLP's current power supply situation and its planned future renewable resource additions, were used to determine the most useful and appropriate amounts of each resource type to include in the generation resource optimization analysis discussed in the next section.

Section 4
GENERATION EXPANSION ANALYSIS

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Section 4
GENERATION EXPANSION ANALYSIS

Following the busbar screening analyses, the generating resource alternatives that were identified as reasonable candidates for further evaluation were combined with the existing resources in a resource expansion optimization model to identify an optimal resource expansion plan. The model used by R. W. Beck incorporates an algorithm that couples a rigorous dynamic programming optimization process with a stochastic[8] representation of uncertain future conditions for load, fuel prices, CO_2 prices, and power prices. The model thus produces a least-cost resource plan (at a given risk tolerance) by simulating the real option cost and value of resource expansion decision-making that occurs in actual utility practice.

Economic and financing assumptions, load forecast, fuel prices, emission allowance prices, generating resource characteristics and costs, and other general assumptions used to perform the generation expansion analysis are consistent with the principal considerations and assumptions identified in Section 2 of this report.

4.1 Stochastic Econometric Regional Forecasting Model

For this IRP Study, R. W. Beck has utilized a proprietary stochastic-dynamic resource optimization-planning model, referred to as the SERF model. The SERF model generates stochastic projections of fuel prices, electric loads for the region and the subject utility (in this case TCLP), emission prices, and power prices. The model simulates corresponding utility power supply costs for multiple potential resource expansion portfolios across all of the stochastic projections. A stochastic-dynamic programming algorithm determines the optimal resource expansion decisions given the future uncertainty in power costs. The general structure of the SERF model is depicted below in Figure 4-1.

SERF consists of three primary modules:

- Stochastic Market Module, which generates stochastic projections of fuel, power prices, utility loads, and emission prices and simulates the build-out and commitment/dispatch of market resources;
- Production Cost Module, which simulates a utility's generating resource commitment and dispatch; and
- Stochastic–Dynamic Optimization Module, which determines a utility's optimal generation expansion plan given uncertain load, market, and commodity price conditions.

[8] Stochastic projections reflect the uncertainty and volatility in forecasting variables such as fuel costs and electric loads. A stochastic projection is usually captured by forecasting future values based on past economic behavior and numerous future outcomes. The resulting stochastic projection provides a range of potential values instead of one forecasted value.

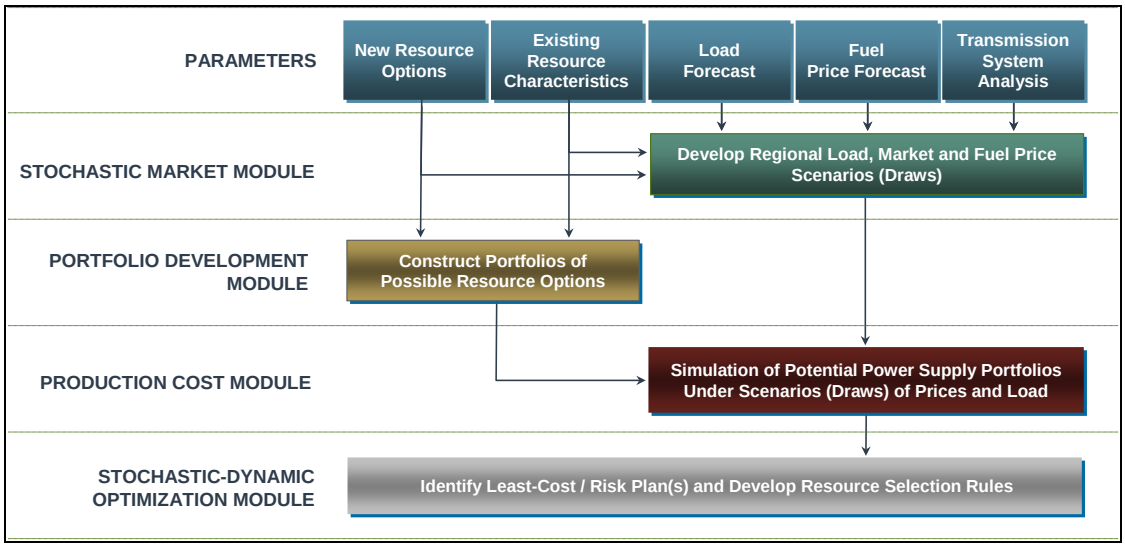

Figure 4-1: SERF Model Overview

A more detailed description of the SERF Model is included in Appendix C.

4.2 Market Simulation Results

Examples of the stochastic forecasts of load, fuel prices, and power prices are depicted in the following figures. More comprehensive market results can be found in Section 3 of Appendix A. These results represent the random stochastic paths produced by the Stochastic Market Module using the expected (or average) values for load, fuel, and emission prices depicted in Section 2 of the report. In the figures, each colored line represents a separate random path, as described above, totaling 50 separate forecasts, with the heavy black lines representing the mean and the 5th and 95th percentiles of the random paths.

The cost of biomass fuel in each year is assumed to vary from the base case, or mean, forecast across the random stochastic paths in the same way as coal prices; therefore, the random paths of biomass fuel prices would look similar to those presented in Figure 4-4.

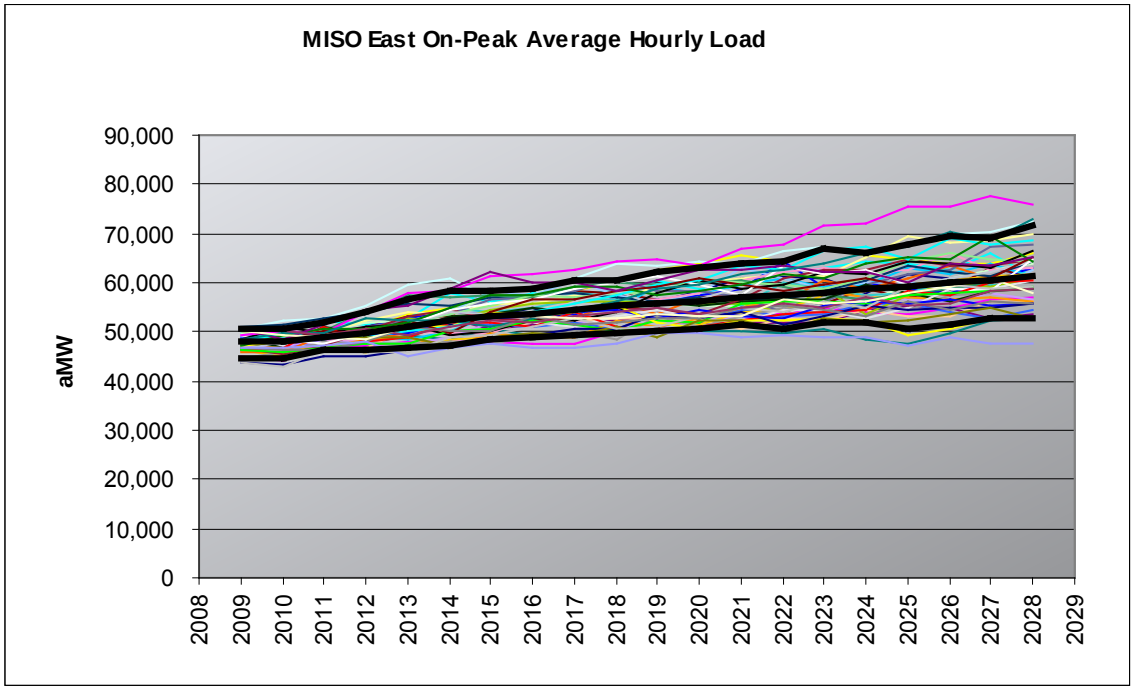

Figure 4-2: MISO East On-Peak Average Hourly Load

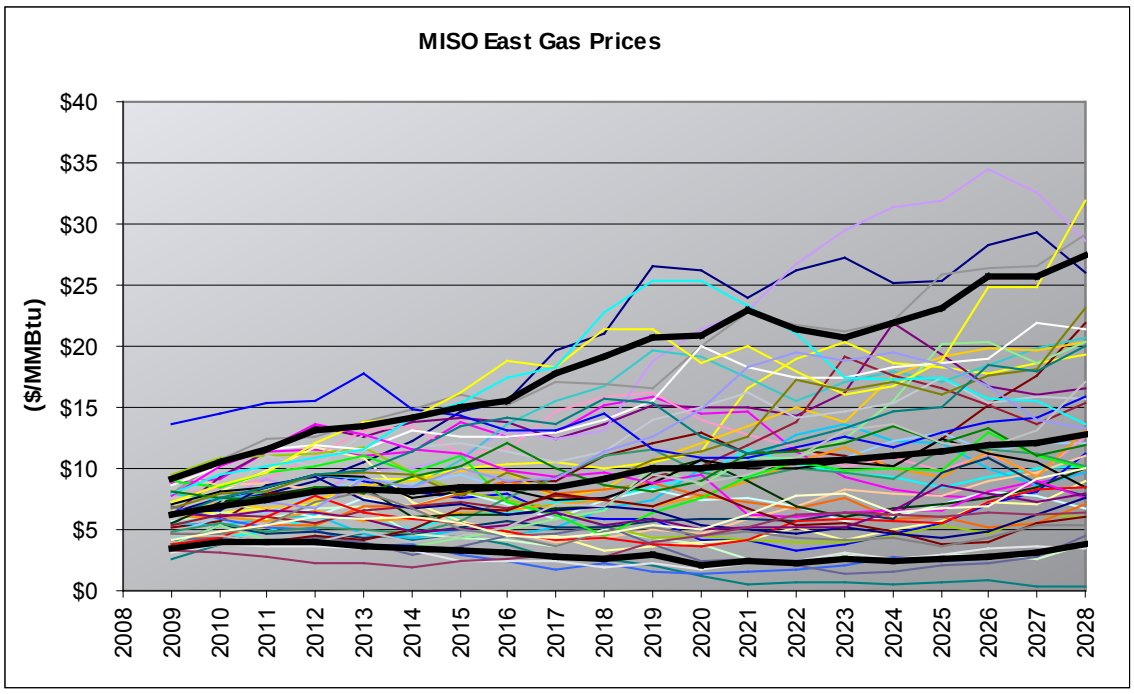

Figure 4-3: MISO East Natural Gas Prices

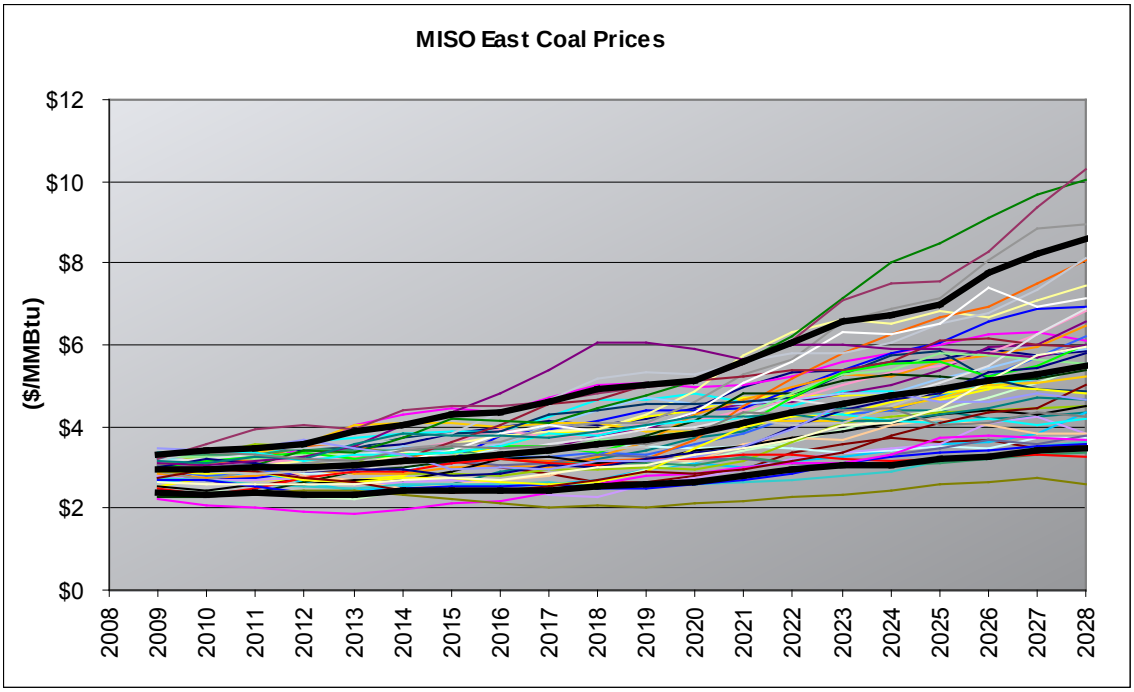

Figure 4-4: MISO East Coal Prices

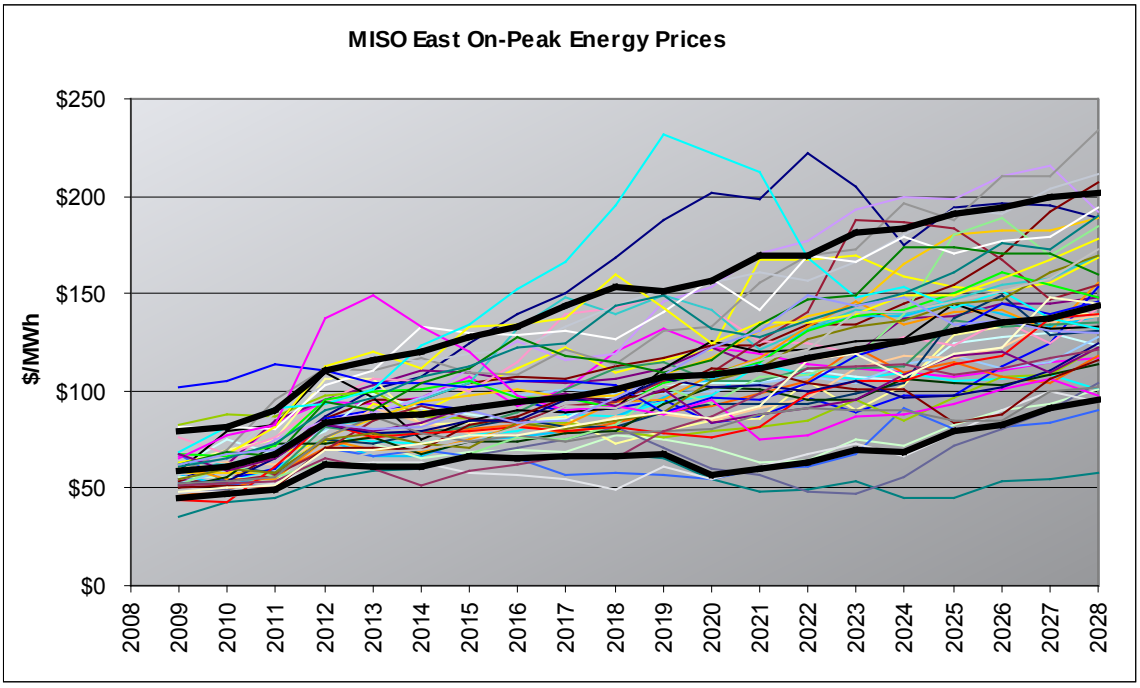

Figure 4-5: MISO East On-Peak Energy Prices

4.3 Generation Resource Expansion Plan Results

In order to utilize SERF to study potential resource expansion plans, it is first necessary to specify the available resource options from which capacity additions can be made, including both their operating characteristics and size. In addition, any restrictions as to the timing of their addition must be specified.

The detailed assumptions related to other generating resource options to be considered by the SERF model are shown in Table 2-8 of Section 2. These options include the following:

- Supercritical pulverized coal-fired steam plant with CCS (SCP Coal with CCS) – 8.5 MW
- Combined cycle gas turbine – 8.0 MW
- Simple cycle combustion turbine – 6.3 MW
- Solar Photovoltaic (PV) – 0.1 MW per year (total of 0.5 MW available)
- Wind Heritage PPA – 10 MW increments based on Heritage PPA prices
- Biomass – 10 MW (as defined by TCLP)

The sizes of the resources shown above are based on the full operating capacity of the assumed technology; with respect to the SCP Coal with CCS resource, it is assumed that TCLP would have an ownership entitlement to a portion of a large-scale facility with a total capacity of 544 MW. In SERF, the resource options are modeled as "slices" of capacity, from which multiple slices can be added through time so that resource expansion plans can be modeled with more flexibility. In order to balance this flexibility but limit the computer processing requirements, the slice sizes and maximum number that could be installed was limited as shown in Table 4-1 below. In addition, the first year of availability for installation was also limited for the SCP Coal with CCS resource to recognize that this technology is not expected to be available for some time. Varying amounts of the Biomass resource were included in the analysis to reflect some uncertainty with respect to TCLP's opportunities to install that capacity locally.

Table 4-1
New Resource Capacity Slice Size

Year	Biomass w/ CHP	Wind PPA	Solar PV	SCP Coal w / CCS	Combined Cycle GT	Simple Cycle GT
Slice Size or Unit Size	10 MW	10 MW	0.1 MW	8.5 MW	8.0 MW	6.3 MW
Maximum Number of Slices	1-3	3	5	2	2	4
First Year of Availability	2015	2015	2015	2018	2015	2015

The Production Cost Module was utilized to dispatch every possible combination of resources given the existing resources, planned future resources, pre-defined renewable resources, and all of the potential resource options and associated size

increments for all years. The Stochastic Dynamic Optimization Module was then used to simulate the pattern of optimal investment decisions to result in a resource expansion plan or portfolio "path", wherein various unit additions are made through time to optimize production costs and risk. The Optimal Plan is defined as the plan that produced the lowest present value average, or levelized, power supply costs over the Study Period, within a given risk tolerance. For this IRP Study, the Optimal Plan was selected on the basis of lowest levelized cost at the 95th percentile, or the point at which the potential levelized costs are only five percent likely to be higher.

In addition to the potential resources discussed above, the IRP Study assumes that TCLP can buy short-term capacity and energy from the market and engage in economy transactions, both based on the results of the simulation of the MISO market, discussed in Appendix A, and on the capital and operating costs of resources projected to be built within the market region. Additional capacity can then be purchased from the market on a short-term basis to meet reserve requirements, and energy can be bought and sold to/from the market to improve the economics of the overall power supply portfolio.

However, for purposes of developing the Optimal Plan, the SERF model was restricted from adding new resources that would cause the total capacity to be significantly above TCLP's capacity requirements (which includes a 15% assumed reserve margin) through the use of an assumed penalty pertaining to build decisions (Over-build Penalty). This cost penalizes additional build decisions above the capacity requirement in each year but is not included in the resulting total power cost projections for any particular portfolio build-out.

Based on some uncertainty with regard to the amount of Biomass capacity that TCLP would consider building, R. W. Beck has developed the following scenarios of the potential maximum number of Biomass "slices", each of 10 MW that the SERF model considered over the Study Period.

- Case 1: One slice of the Biomass resource option (totaling 10 MW).
- Case 2: Two slices of Biomass.
- Case 3: Three slices of Biomass.

Figure 4-6 depicts the optimal resource expansion plan for TCLP based on the assumptions described in Section 2 and the consideration of only one Biomass unit. The analysis suggests an expansion plan with TCLP's existing resources, including the 10 MW of the Heritage Wind PPA, and the 10 MW Biomass resource, brought online in the first year available, 2015.

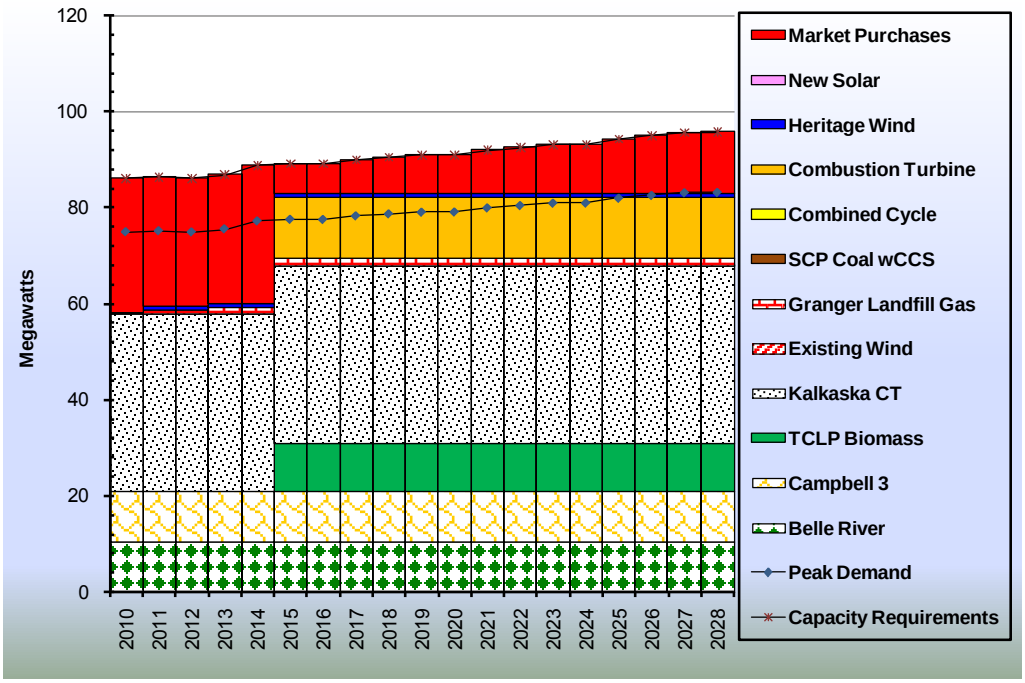

Figure 4-6: Optimal Plan – Case 1

Figure 4-7 below depicts the range of projected annual average power costs under the Case 1 Optimal Plan. The lines shown include the expected value, or mean, across the draws and the 5th and 95th percentiles, encompassing 90 percent of the potential power costs. In the upper left corner of the graph is shown the levelized power costs over the Study Period and the standard deviation, given the uncertainty in costs and loads.

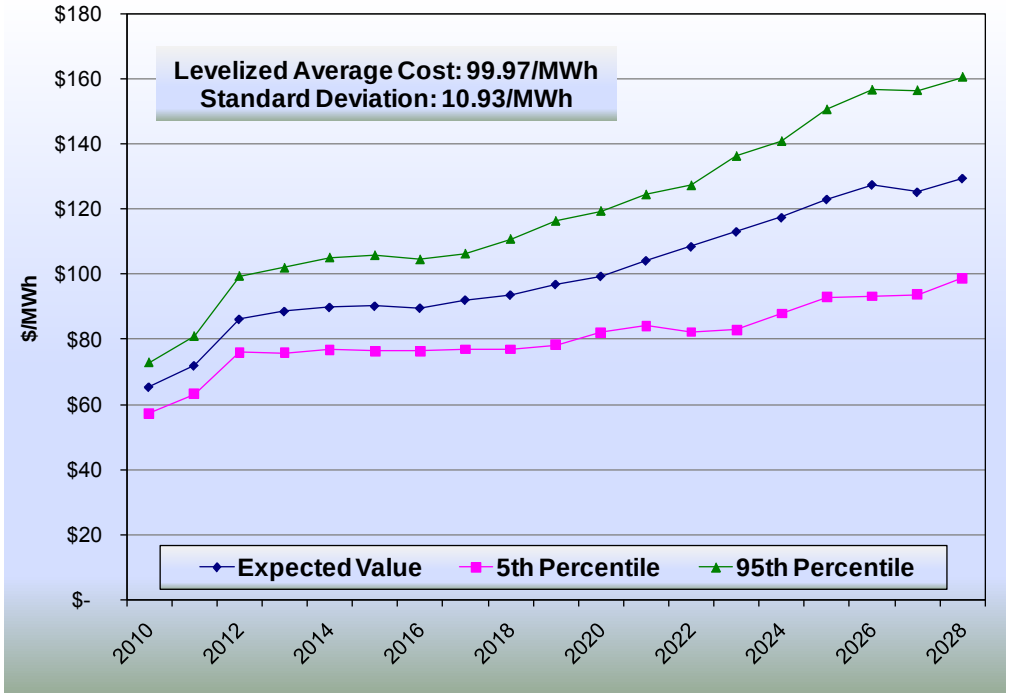

Figure 4-7: Range of Power Supply Costs – Case 1

Similarly, Figures 4-8 and 4-9 below depict the optimal resource expansion plan for TCLP, based on the consideration of up to two Biomass units, and the resulting range of projected annual average power costs, along with the levelized cost and standard deviation across the draws. Similar to the Case 1 results, the full amount of available Biomass capacity (20 MW) is brought online in the first available year. Most of the remaining capacity needs are fulfilled through the addition of approximately 6.3 MW of combustion turbine capacity.

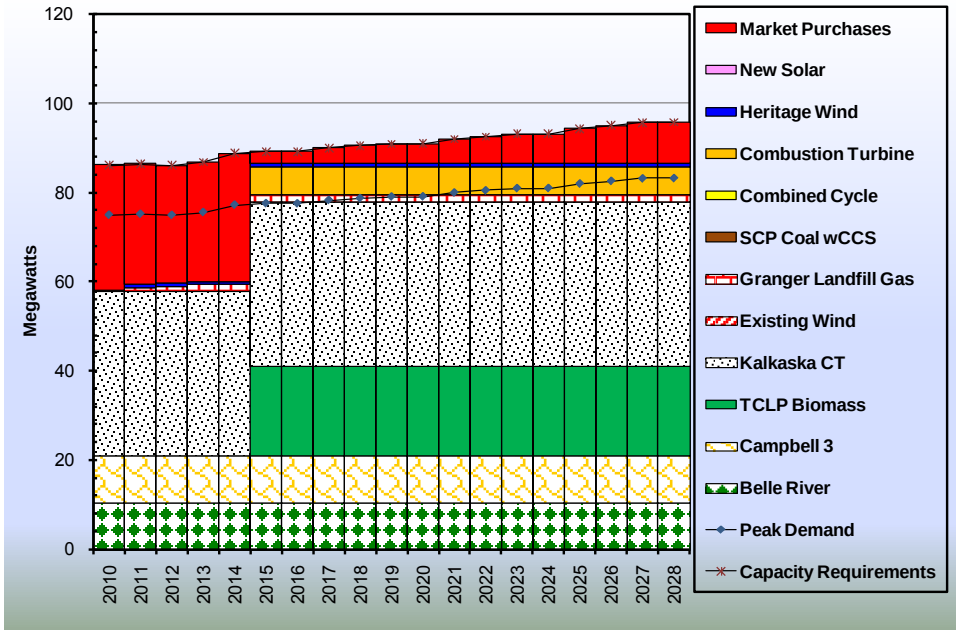

Figure 4-8: Optimal Plan – Case 2

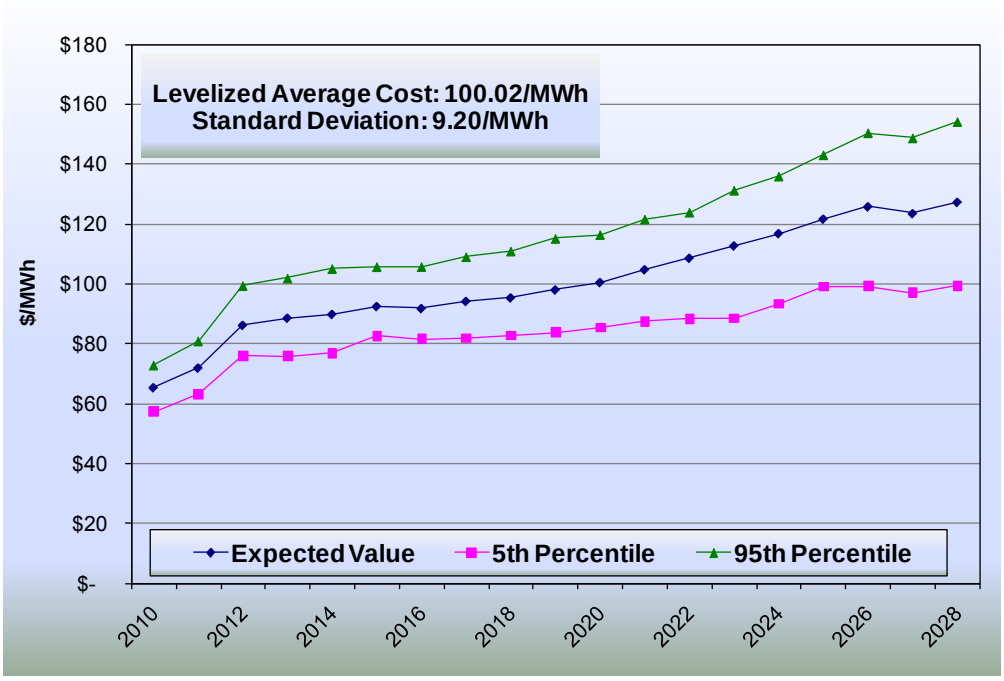

Figure 4-9: Range of Power Supply Costs – Case 2

Finally, Figures 4-10 and 4-11 below depict the optimal resource expansion plan and the resulting range of projected annual average power costs for Case 3. Similar to the results for Cases 1 and 2, the upper limit of 30 MW of Biomass capacity is selected for installation, the first two units of 10 MW each in 2015 and the third unit in 2016 or thereafter. This amount of capacity, combined with TCLP's existing resources meets nearly all of TCLP's capacity needs over the Study Period, with the rest being fulfilled with short-term capacity purchases.

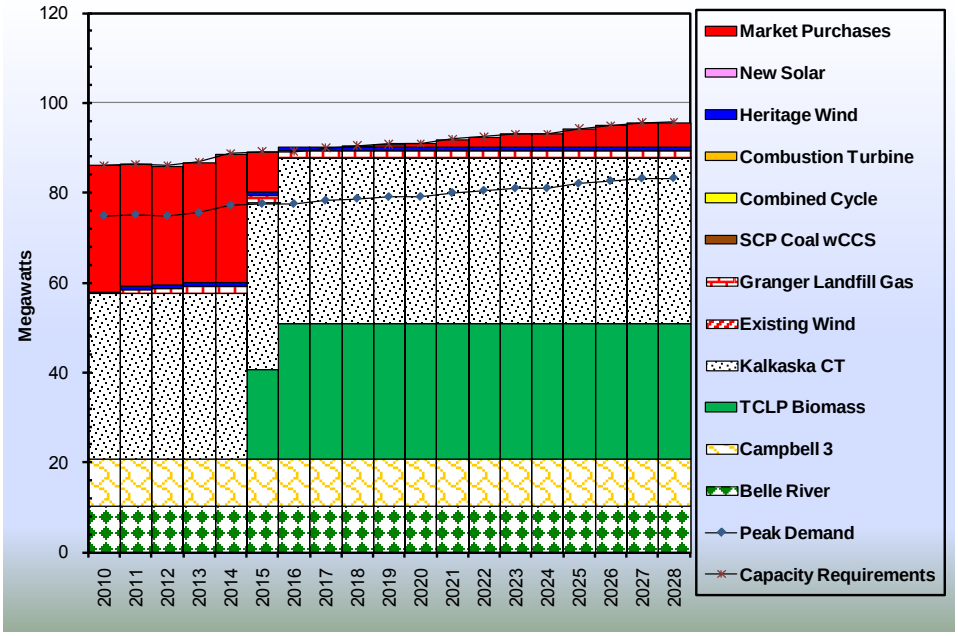

Figure 4-10: Optimal Plan – Case 3

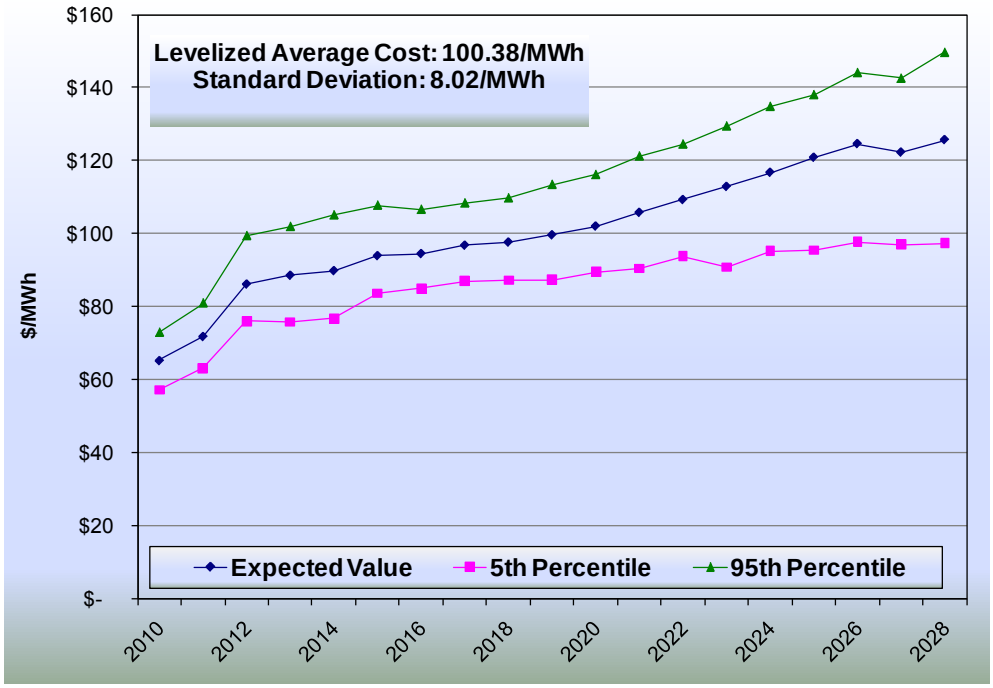

Figure 4-11: Range of Power Supply Costs – Case 3

4.3.1 Sensitivity of Results to Higher Gas Prices

The power market projections produced as part of this IRP Study were developed in June 2009, and some of the fuel price projections in early 2009. Since late 2008, natural gas prices have fallen, from a peak in 2008 of about $12/MMBtu to a more recent range of $4 - $6/MMBtu. However, it is uncertain whether these lower natural gas prices will be sustainable in the long-term, particularly given the potential for greenhouse gas legislation. The natural gas price forecast for the expected case reflects significantly higher gas prices than those experienced since late 2008 but considerably lower over the next several years than the mid-2008 period.

In order to assess the sensitivity of the Optimal Plans to higher and lower natural gas prices, Cases 1 through 3 (again corresponding to varying levels of maximum allowed Biomass capacity) were re-simulated with higher and lower natural gas prices, set to the 70th and 30th percentiles, respectively. The resulting gas prices correspond to levels at which gas prices are only 30% likely to be higher or lower, respectively. Under the High Gas Prices sensitivity case, gas prices are on average approximately 27% higher than the expected gas prices. Under the Low Gas Prices sensitivity case, gas prices are on average approximately 21% lower than the expected prices.

The results of this scenario showed that the Optimal Plans in each case were essentially unaffected by the High Gas Prices sensitivity. This is primarily because the Optimal Plans already resulted in essentially the maximum amount of Biomass capacity possible being selected. The Combustion Turbine capacity selected in Cases 1 and 2 were also unaffected, as the market is similarly influenced by natural gas prices as the operating costs of this technology. However, the resulting market prices are still not high enough to warrant the higher capital costs of building the SCP Coal with CCS resource or additional renewable resources.

The Low Gas Prices sensitivity resulted in Optimal Plans reflecting delays in the build-out of Biomass capacity. However, the ultimate amount of Biomass capacity that was reflected in the Optimal Plan was the same. Figure 4-12 provides an example, using the results of Case 2, which corresponds to a maximum allowed Biomass capacity of 20 MW. As compared to the results under expected gas prices, shown in Figure 4-8, the Optimal Plan under this sensitivity reflects only 10 MW of Biomass capacity added in 2015, with the remaining allowed 10 MW not built until 2026. The 6.3 MW of Combustion Turbine capacity is also added in 2015, as in the expected case. The Low Gas Prices sensitivity also reflects the market being relied upon for a greater share of capacity and energy needs.

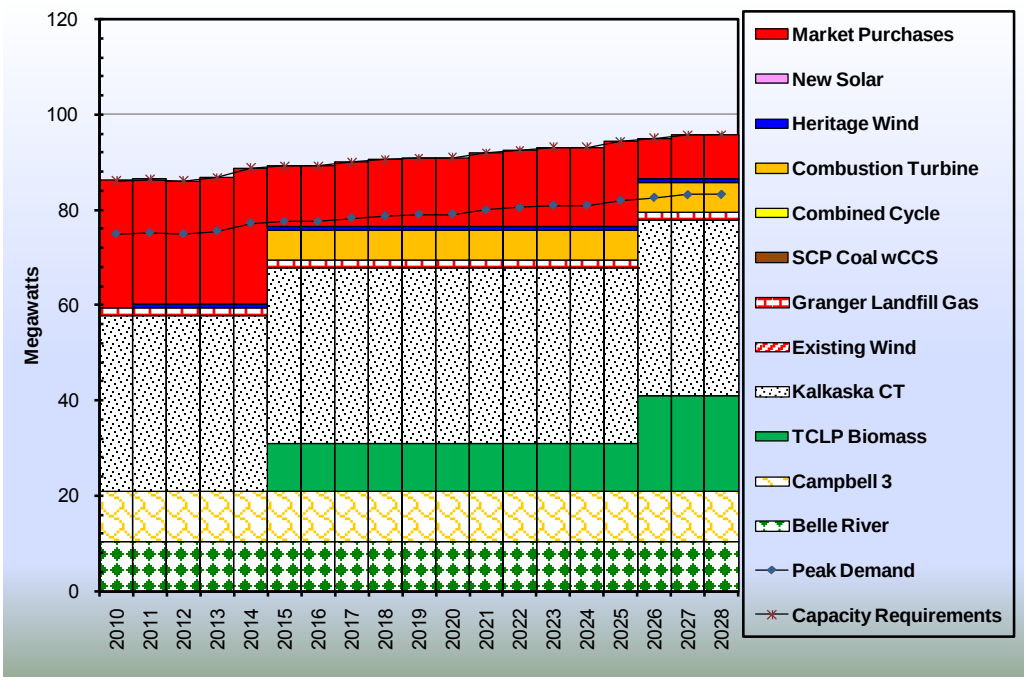

Figure 4-12: Optimal Plan – Case 2 (Low Gas Prices Sensitivity)

4.3.2 Comparison of Optimal Plan Cases 1 – 3

Figure 4-13 below compares the expected annual power supply costs under the three Optimal Plan Cases discussed above as compared to the Existing Resources. The comparison shows that although the annual power costs are fairly close throughout much of the Study Period, the Optimal Plan Cases are projected to be significantly lower than the Existing Resources case beginning 2021. This is most likely the result of projected increases in the cost of CO2 emissions due to the reduction in the number of free allowances under the Lieberman-Warner carbon legislation.

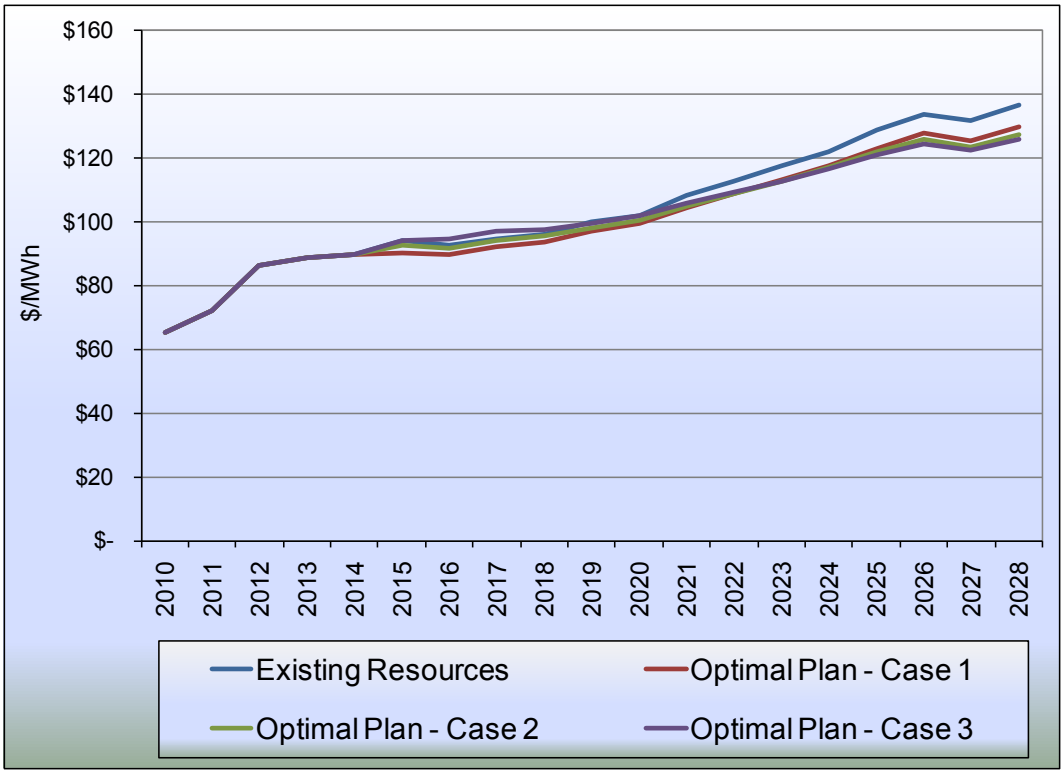

Figure 4-13: Expected Power Supply Costs

Figure 4-14 below provides a comparison of the three alternative expansion plans in the form of an X-Y chart, which combines both the levelized power cost over 2011-2028 for each plan and its standard deviation. The relative position of each plan along the X- and Y-axes corresponds to a trade-off between a preference for lower expected costs and a preference for projected costs of greater certainty (i.e., lower standard deviation), with points closer to the origin being overall more preferential. It is up to the utility planner to determine the acceptable trade-off between resource plans of lower cost versus those of lower uncertainty.

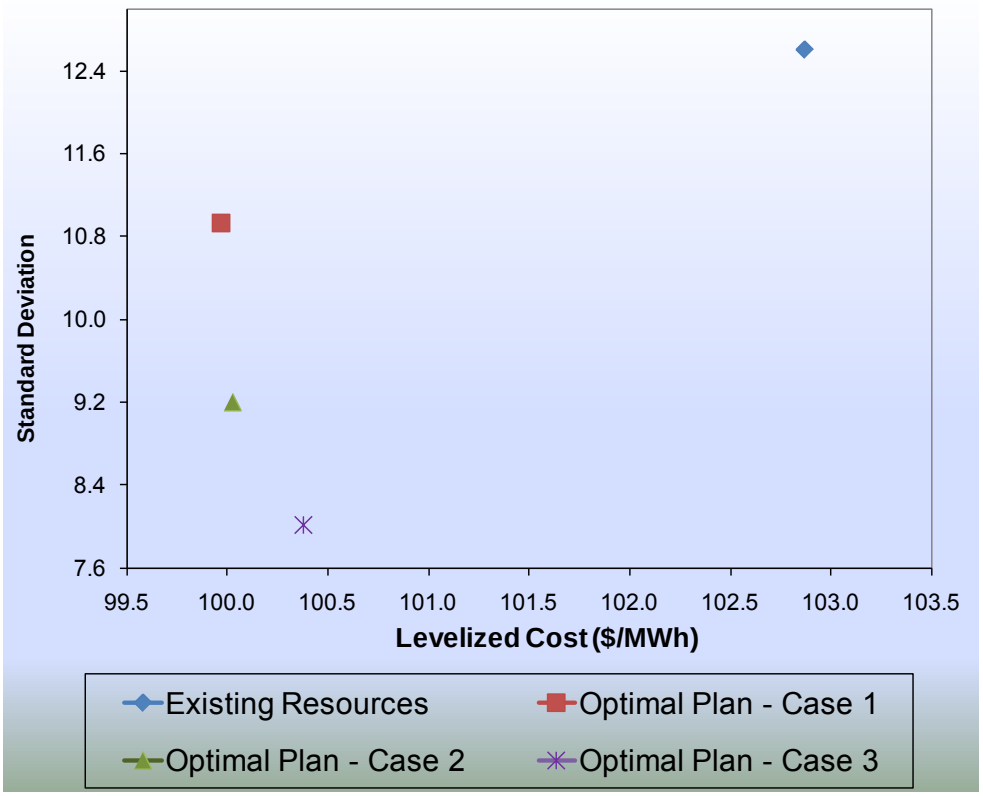

Figure 4-14: Power Supply Costs Comparison

The results reflect that the Optimal Plans result in lower average levelized cost than the Existing Resources, and that they also successively lower the standard deviation of levelized power costs across the draws. The Optimal Plans add a significant amount of Biomass capacity, which both lowers the average levelized cost and significantly lowers the variability in levelized cost, which is evident in the lower standard deviation. This is most likely driven from the fact that the Biomass resource utilizes fuel that is subject to less volatility than gas-fired resources, based on the assumptions relied on herein, which also influence market prices more so than other fuel types.

Figure 4-15 below provides a similar comparison as that shown above. However, rather than charting the standard deviation on the Y-axis, the value on the Y-axis is the projected levelized power costs at the 95th percentile. This provides a measure of exposure to high power costs under each resource expansion case rather than simply how large the spread in potential costs might be (which includes the effects of both high and low cost uncertainty).

Similar to the conclusions associated with Figure 4-14 above, Figure 4-15 shows that the Optimal Plans generally result in successively lower levelized power costs on an expected value basis but also at the 95th percentile. This is most likely a function of the much greater stability of fuel costs of the Biomass resource, which are assumed to have similar volatility and uncertainty as coal prices, than market purchases.

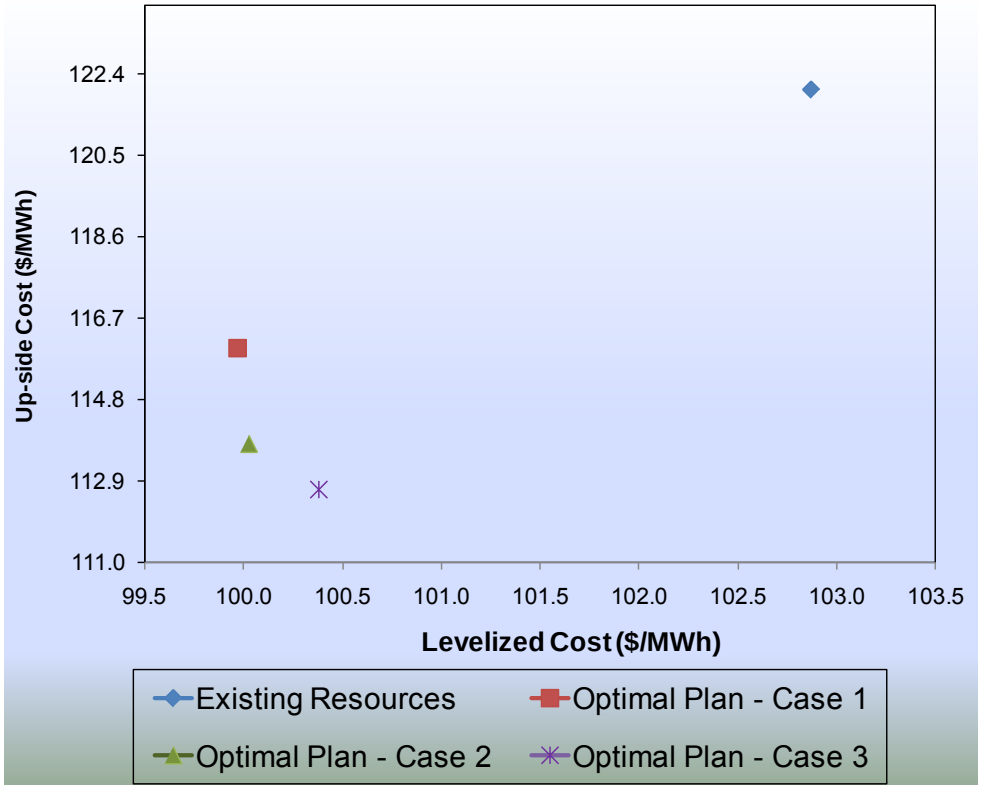

Figure 4-15: High-range of Potential Power Supply Costs

The overall results discussed above suggest that, given the resource options that have been considered and the assumptions discussed in Section 2, TCLP should consider building up to 20-30 MW of Biomass capacity to be brought online over 2015-2026. These units are intended to operate at high capacity factors, and indeed must be to support steam or hot water sales to which they would be tied. Given that amount of capacity and TCLP's other resources, it is estimated that as much as 40% of the energy generated by this amount of Biomass capacity would be surplus to be sold into the wholesale market for the first several years of the Study Period. While the risks associated with this surplus energy are accounted for in the simulations that support the additions of Biomass capacity, TCLP should consider its tolerance for risk and perhaps limit its exposure somewhat. Accordingly, the Case 2 results, which consist of the additions of 20 MW of Biomass capacity and approximately 6.3 MW of Combustion Turbine capacity appear most reasonable and representative of balancing TCLP's goals of lowest cost and minimizing risk, while also achieving the goal of a significant renewable generation percentage, as discussed below. Given the results of the Low Gas Prices sensitivity, TCLP might consider building a smaller amount of Biomass capacity in the 2015 timeframe and building additional capacity somewhat later. This would afford TCLP some flexibility in the event that the relatively low natural gas prices that are evident today appear likely to be sustained in the long-term.

Appendix D contains summary tables of the resulting load and resource balance and projected power supply costs for each of the three resource expansion plans over the period 2011 through 2028.

4.3.3 TCLP Renewable Generation

Figure 4-16 below provides a graphical representation of the projected amount of renewable generation in TCLP's portfolio as compared to the REP goal outlined in Michigan Public Act 295. The chart shows that the Existing resources with the Heritage PPA are well above the state requirements through 2014 and exactly meet the current State REP Goal for 2015 and beyond. The additions of significant amounts of Biomass capacity reflected in the Optimal Plans result in renewable generation that far exceed the State REP requirement, as well as TCLP's RPS goal, over the Study Period.

The State REP Goal shown below is intended to represent how that legislation will be interpreted for purposes of tracking TCLP's renewable requirements. The growth in the renewable percentage through 2015 is based directly on the percentages outlined in the legislation, while the percentages beyond 2015 are based on the amount of renewables required in 2015 applied to the forecasted energy requirements, net of the EOP, over the forecast horizon. This results in a slightly declining required share of renewable generation, as TCLP's energy requirements are forecasted to grow by 0.9% per year over 2010-2028.

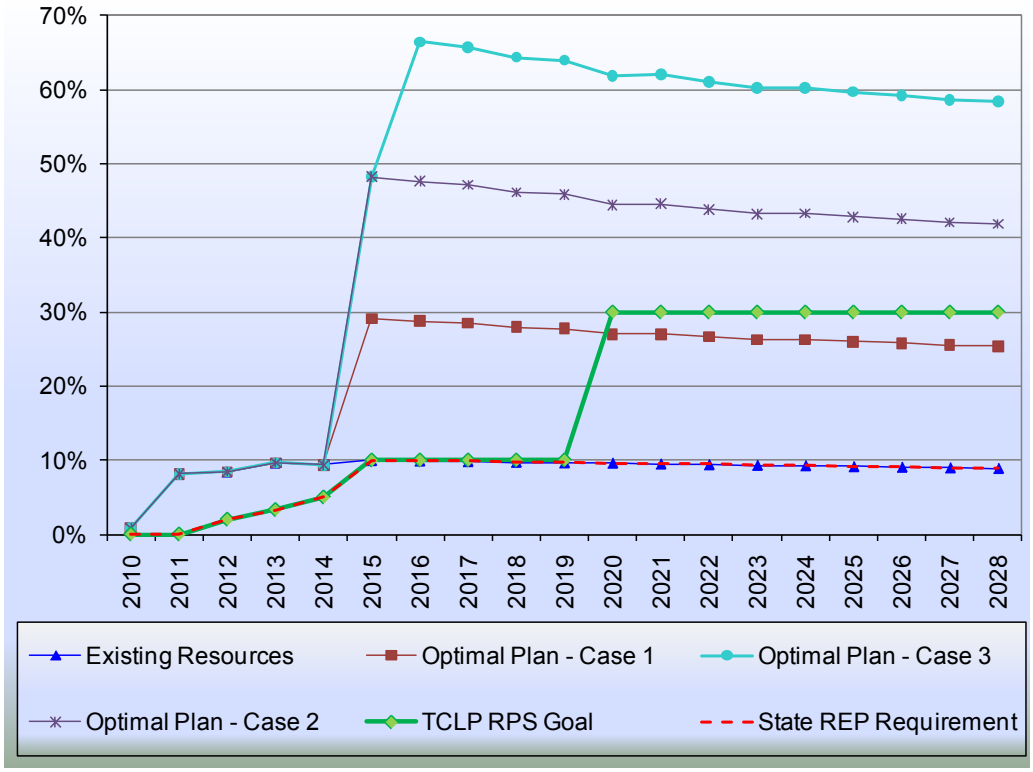

Figure 4-16: TCLP Renewable Energy vs RPS Requirements

Appendix A
MISO EAST MARKET REPORT – REGIONAL POWER PRICE FORECAST

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Appendix A
MISO EAST MARKET REPORT – REGIONAL POWER PRICE FORECAST

A.1 Stochastic Market Module Description

A.1.1 Overview

For the IRP Study, the R. W. Beck proprietary Stochastic Econometric Regional Forecasting ("SERF") model was used. The SERF model generates stochastic projections of fuel prices, electric loads for the region and the subject utility (in this case TCLP), emission prices, and power prices. The model simulates corresponding utility power supply costs for multiple potential resource expansion portfolios based on the stochastic projections. The Stochastic Market Module generates stochastic projections of fuel, power prices, utility loads, and emission prices and simulates the build-out and commitment/dispatch of market resources

A more detailed description of the SERF Model is included in Appendix C.

A.2 Market Module Inputs and Assumptions

A.2.1 Study Period

Price forecasts will be developed for a 20 year period beginning January 1, 2009 and ending December 31, 2028.

A.2.2 Time Periods

On-peak hours are defined by hour ending 8:00 to 23:00 EST during week days, and off-peak hours are defined as all other hours. Summer months are defined as June through September of each year.

A.2.3 Escalation Factors

R. W. Beck has based the capital and operation and maintenance cost escalation factors utilized in our power supply planning models on the Blue Chip Economic Indicators (BCEI) dated March 2009. The BCEI forecast reflects the impacts of the current economic recession and projects an inflation rate, as measured by the Consumer Price Index (CPI), of -0.8% for 2009. The economy is projected to contract significantly in 2009, with a recovery in 2010. The long-term average annual rate of inflation projected in the BCEI is 2.4%.

With regard to capital cost escalation, R. W. Beck's assumption is based on our Project Cost Estimator forecast, which is developed from future capital costs escalation rates included in recent construction contracts; materials, equipment, and labor cost indices projected by Global Insight, Inc.; and R. W. Beck's experience in the industry. The current escalation adder for future capital costs is equal to our general inflation assumption discussed above for the duration of the Study Period.

A.2.4 Regions

The Eastern interconnect power market model incorporates the regions shown in Figure A-1. The region of interest for Traverse City Light & Power is MISO East, which primarily comprises the utilities in Michigan, FirstEnergy in Ohio, and utilities in central and southern Indiana and Illinois. Each region is assumed to have a required reserve margin of 15%. Transmission transfer limits between the regions, in terms of both energy and capacity, were estimated by R. W. Beck transmission experts based on their familiarity with the regions.

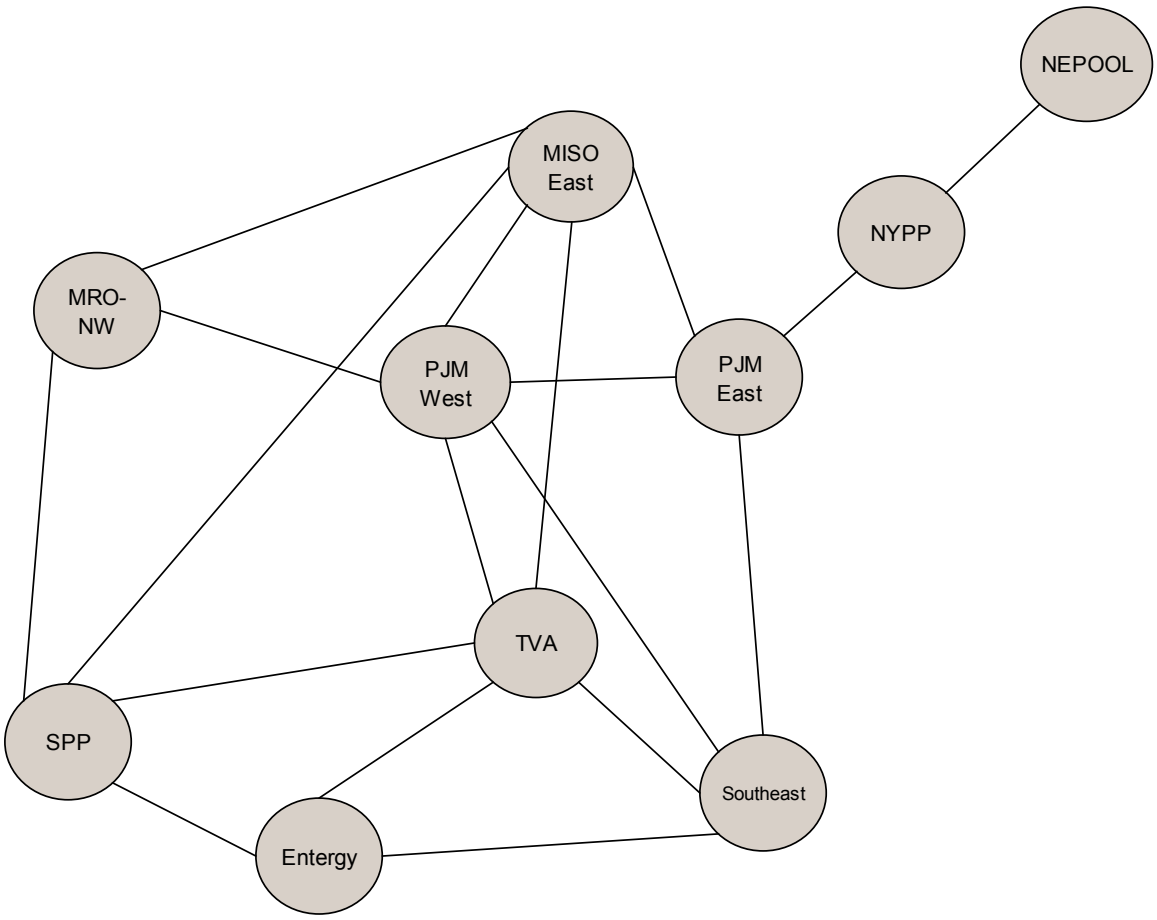

Figure A-1: Eastern Interconnection Ball and Stick

A.2.5 Natural Gas Price Forecast

R. W. Beck maintains proprietary economic models, which are updated each quarter, to project the market price of natural gas at Henry Hub and 111 market areas throughout North America (the "NG Model"). R. W. Beck's NG Model projects monthly Henry Hub prices from a number of key variables including natural gas storage levels (as compared to "typical" levels), utilization of productive capacity, well costs, the price of crude oil, and other factors which describe the "health" of gas deliverability in the near term. Production and other supply drivers in the NG Model are driven by exploration and development activity that is largely the result of prior period prices. Certain aspects of gas supply are based on assumptions regarding the decline rate for existing wells and new well productivity and decline rates which are derived from data provided by Lippman Consulting, Inc. and other external sources.

Table A-1 presents R. W. Beck's current Natural Gas Forecast, showing an average of delivered gas prices within the MISO East region, adjusted to reflect the slight negative inflation expected for 2009.

Table A-1
Gas Price Forecasts ($/MMBtu)
Nominal Prices

Historical	
2005	9.19
2006	7.03
2007	7.36
2008	9.29
Projected	
2009	6.18
2010	6.93
2011	7.50
2012	8.08
2013	8.35
2014	8.02
2015	8.38
2016	8.45
2017	8.49
2018	9.08
2019	9.94
2020	10.04
2021	10.28
2022	10.52

Projected	
2023	10.76
2024	10.99
2025	11.38
2026	11.94
2027	12.02
2028	12.83

A.2.6 Coal Price Forecast

Table A-2 presents R. W. Beck's 2008 Fourth Quarter Coal Forecast, showing the average of delivered coal prices within the MISO East region. R. W. Beck uses projections from J. T. Boyd to develop regional delivered coal price forecasts. R. W. Beck and J. T. Boyd work together to develop an outlook for coal supply and demand as part of a teaming agreement.

Table A-2
Regional Coal Price Forecasts ($/MMBtu)
Nominal Prices

Historical	
2005	1.39
2006	1.53
2007	1.59
2008	1.83
Projected	
2009	2.92
2010	2.95
2011	2.98
2012	3.01
2013	3.04
2014	3.15
2015	3.23
2016	3.33
2017	3.44
2018	3.56
2019	3.69
2020	3.85
2021	4.09
2022	4.33

Projected	
2023	4.57
2024	4.75
2025	4.92
2026	5.11
2027	5.29
2028	5.49

A.2.7 Emissions Allowance Price Projections

SO_2 and NO_X Allowance Prices

R. W. Beck has developed a proprietary SO_2 and NO_X allowance price forecasting model. This model is integrated with other energy market simulation models utilized by R. W. Beck.

The forecast is developed by simulating the operation of the U.S. power system over the Study Period using the PROMOD and MarketPower models developed by Ventyx. The emissions from each power plant unit are calculated and allowance prices are derived from simulated decisions to install emission control technologies on individual units. It is assumed that future allowance prices will be directly related to the cost of retrofitting units with emission control technologies.

A target emission level is assumed for each year so as to be compatible with current emission regulations. Total costs for installing and operating scrubber, selective catalytic reduction, selective non-catalytic reduction controls and low NO_X burners are estimated for each generating unit from proprietary cost functions. This total cost expressed as an annual expense, divided by tons abated gives the annual dollars per ton cost. For each forecast year, decisions to install controls are simulated starting with the least cost units until the target emission level for the year is satisfied. The last unit to install controls determines the forecast allowance price for that year – the dollars per ton abatement cost is taken as the clearing price. The process and integration with other market simulation models is iterated until stable emissions clearing prices are reached.

The allowance prices that result from the model reflect costs at long-term equilibrium. Short- and medium-term market factors may cause spot and/or forward market allowance prices to deviate higher or lower from the equilibrium. So as to better represent the current market conditions, market forward and spot prices for SO_2 and NO_X allowances (to the extent they are available) are blended with the modeled equilibrium prices. Market prices are averaged with the modeled equilibrium price at various weightings to arrive at the final forecast prices. Weightings are determined based upon the amount of available forward data, with near term years weighted more heavily to the market price and later term years weighted more heavily to the modeled

equilibrium price. Prices for years beyond available market data are the modeled equilibrium price from the model.

CO_2 Allowance Prices

R. W. Beck has a proprietary green house gas ("GHG") model that captures the relationship between CO_2 allowance prices, power demand and prices, natural gas demand and prices, and other fuel demand and prices. This market simulation model divides the U.S. into multiple interconnected regions, simulates the retirement of existing units if they are not profitable, and constructs new replacement units to meet reserve requirements. The potential build out of new units includes traditional fossil-fueled technologies (coal-fired supercritical, natural gas-fired combined cycle, and combustion turbines) and also nuclear generation, wind and solar generation, and new technologies such as coal generation with carbon capture and sequestration. The model simulates the energy industry response to an assumed CO_2 allowance price, including gas consumption (and gas price response), CO_2 emissions, and demand response. The model iterates on the CO_2 allowance price until a balanced gas consumption/gas price/load demand response solution is obtained that meets the required power sector CO_2 reductions based on a national GHG target.

The projected new generating resource capital costs and operating costs and characteristics are developed in conjunction with R. W. Beck's Global Asset Consulting practice. Our engineers have experience in all power generation technologies, have projected new technology costs, and have compiled a database with information on costs related to construction and financing of new units.

Our carbon model reflects the potential reductions in the power sector, but anticipated future federal legislation will likely create a national market that crosses all sectors. Many cost effective measures, both on the demand-side of the power sector and in other sectors, can be implemented before supply-side solutions in the power industry (retrofitting existing plants, retiring existing coal-fired generation, building nuclear, and carbon capture and sequestration) become competitive.

At the point when power sector supply-side measures are required to meet mandated GHG reductions, their control costs will begin to set the marginal price for allowances. Early on, carbon reductions will most likely come from other sectors, and the power sector will be a net purchaser of allowances. Within our model, we assume that, over time, CO_2 allowance prices will increase to the power sector marginal costs as power sector supply side options are needed for further carbon reductions.

CO_2 Allocations

Based on recent legislation that has gone through extensive debate in the U.S. Senate process, which is representative of regional concerns, many of the plans allow for some percentage of the allowances to be freely allocated and the remainder to be auctioned. Free allowances represent an opportunity cost and based on evidence from the Acid Rain program and the EU-ETS program, generators do not pass on the savings from them. Instead, they bid in full emission costs and either use the free

allowances for compliance or sell them. Therefore, the market prices do not reflect the allocation of free allowances.

Table A-3
Allowance Prices ($/ton)

Year	NO_X Summer[1]	NO_X Annual	SO_2	Expected Value CO_2
2009	441	986	196	-
2010	401	941	476	-
2011	386	912	675	-
2012	382	906	855	12.00
2013	381	906	1,046	13.08
2014	378	901	1,187	14.61
2015	380	908	1,330	16.30
2016	383	918	1,426	18.20
2017	389	934	1,517	20.32
2018	399	957	1,576	22.68
2019	410	985	1,627	25.31
2020	420	1,009	1,675	28.26
2021	439	1,055	1,758	31.06
2022	454	1,089	1,810	35.82
2023	465	1,116	1,869	40.02
2024	481	1,154	1,965	45.65
2025	492	1,181	2,013	49.88
2026	504	1,210	2,052	52.88
2027	516	1,237	2,069	55.60
2028	529	1,269	2,152	57.16

[1] NOx allowance price shown for the summer reflects the sum of seasonal price adder for the summer.

Table A-4
CO_2 Probability Distribution ($/ton)

Year	0%	10%	20%	40%	20%	10%	Expected Value
2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	6.00	9.00	12.00	15.67	19.33	12.00
2013	0.00	6.40	9.74	13.08	17.16	21.23	13.08
2014	0.00	7.00	10.80	14.61	19.27	23.93	14.61
2015	0.00	7.65	11.98	16.30	21.58	26.86	16.30
2016	0.00	8.37	13.29	18.20	24.21	30.22	18.20
2017	0.00	9.16	14.74	20.32	27.14	33.97	20.32
2018	0.00	10.03	16.35	22.68	30.41	38.15	22.68
2019	0.00	10.99	18.15	25.31	34.06	42.80	25.31
2020	0.00	12.04	20.15	28.26	38.18	48.10	28.26
2021	0.00	12.99	22.02	31.06	42.10	53.15	31.06
2022	0.00	14.71	25.27	35.82	48.72	61.61	35.82
2023	0.00	16.15	28.08	40.02	54.61	69.20	40.02
2024	0.00	18.10	31.88	45.65	62.49	79.32	45.65
2025	0.00	19.45	34.66	49.88	68.47	87.06	49.88
2026	0.00	20.27	36.58	52.88	72.81	92.73	52.88
2027	0.00	20.96	38.28	55.60	76.77	97.93	55.60
2028	0.00	21.21	39.18	57.16	79.13	101.10	57.16

A.2.8 Regional Resource Options

Tables A-5 and A-6 present the generic resource options to be used in the analysis and their associated costs, financing parameters, and operating characteristics. These resource characteristics will be used to develop regional price forecasts. The capital costs shown below represent the estimated total costs in 2008 dollars including construction costs, interest during construction, transmission interconnection costs and an allowance for other owners' costs. The financial assumptions shown for Peaking and Combined Cycle Units are based on the capital structure of developers for merchant plants, whereas the baseload resource (Coal and Nuclear units) assumptions are based on the capital structure of regulated utilities in the region.

Table A-5
Regional Generic Resource Characteristics

	Peaking		Combined Cycle			Coal	
	LM6000	F Class GT	F Class 1x1	FB Class 2x1	H Class 2x1 [1]	SCPC	IGCC with CCS [2]
Maximum Capacity (MW)	47	168	254	518	778	784	605
Capital Cost (2008$/kW; MISO East)	$979	$654	$1,399	$1,128	$954	$3,575	$5,556
Debt/Equity Ratio	50/50	50/50	50/50	50/50	50/50	50/50	50/50
Interest Rate (%)	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
After Tax Return on Equity (%)	13.5%	13.5%	12.5%	12.5%	12.5%	11.0%	11.0%
Composite Annuitized Rate [3]	9.65%	9.65%	9.41%	9.41%	9.41%	7.77%	7.77%
Financing Period (years)	20	20	20	20	20	30	30
First Year of Installation	2010	2010	2010	2013	2018	2013	2018
Last Year of Installation	2050	2050	2050	2050	2050	2050	2050
Fixed O&M (2008$/kW-yr)	$12.0	$15.2	$19.5	$19.5	$19.5	$44.0	$61.6
Variable O&M (2008$/MWh)	$2.0	$13.9	$3.1	$3.1	$3.1	$1.9	$5.7
Full-Load Heat Rate (Btu/kWh)	9,698	10,302	7,195	7,039	6,677	9,240	10,950
NO_X Emission Rate (lb/MMBtu)	0.0100	0.0100	0.0100	0.0100	0.0100	0.0700	0.006
SO_2 Emission Rate (lb/MMBtu)	0.0006	0.0006	0.0006	0.0006	0.0006	0.1000	0.02
CO_2 Emission Rate (lb/MMBtu)	120.0	120.0	120.0	120.0	120.0	210.0	21.0
Maintenance Rate (%)	1.0%	1.0%	1.0%	5.0%	5.0%	9.0%	9.0%
Forced Outage Rate (%)	3.0%	3.0%	3.0%	2.0%	2.0%	6.0%	6.0%

[1] H Class CC phased in between 2015 and 2020.
[2] IGCC w/ CCS phased in between 2018 and 2020.
[3] Internal Rate of Return that when used in a mortgage style calculation yields a rate that will recover the fixed costs of a utility, including depreciation, return on investment, and taxes.

Table A-6
Regional Generic Resource Characteristics (Nuclear and Renewables)

	Renewables[1]		Nuclear
	Wind Farm	Solar	Two Units[2]
Maximum Capacity (MW)	101	192	1,323
Capital Cost (2008$/kW; MISO East)	$2,439	$5,963	$5,873
Debt/Equity Ratio			50/50
Interest Rate (%)			9.0%
After Tax Return on Equity (%)			11.0%
Composite Annualized Rate [3]			7.44%
Financing Period (years)	20	20	30
First Year of Installation	2010	2010	2018
Last Year of Installation	2050	2050	2050
Fixed O&M (2008$/kW-yr)			$77.5
Variable O&M (2008$/MWh)			$3.0
Full-Load Heat Rate (Btu/kWh)			10,530
NO_X Emission Rate (lb/MMBtu)	-	-	-
SO_2 Emission Rate (lb/MMBtu)	-	-	-
CO_2 Emission Rate (lb/MMBtu)	-	-	-
Maintenance Rate (%)			6.0%
Forced Outage Rate (%)			4.0%

[1] Provided for informational purposes only. Renewable resources are added to each region in amounts sufficient to fulfill the RPS requirements set forth in Table A-7.
[2] Maximum nuclear plant additions limited to one new two-unit plant per region per year.
[3] Internal Rate of Return that when used in a mortgage style calculation yields a rate that will recover the fixed costs of a utility, including depreciation, return on investment, and taxes.

A.2.9 State Renewable Portfolio Standards

Without a federal Renewable Portfolio Standard (RPS), adoption and enforcement of RPS have primarily taken place at the state level. R. W. Beck has developed regional weighted average RPS fulfillment rates for the MISO East region that reflects a combination of state-level standards and goals in place as of February 2009. It is important to note that we have not included any proposed standards that have not yet been passed. For the MISO East region, we have assumed that the RPS will be met with a combination of wind and solar resources, as shown in Table A-7 below.

Table A-7
Assumed RPS Fulfillment Rates for the MISO East Region

Year	Wind Resources	Solar Resources
2009	1.2%	0.02%
2010	2.3%	0.04%
2011	3.5%	0.05%
2012	4.7%	0.07%
2013	5.9%	0.09%
2014	7.0%	0.11%
2015	8.2%	0.13%
2016	9.0%	0.14%
2017	9.9%	0.16%
2018	10.7%	0.18%
2019	11.5%	0.20%
2020	12.3%	0.22%
2021	12.8%	0.24%
2022	13.2%	0.24%
2023	13.7%	0.25%
2024	14.1%	0.26%
2025	14.5%	0.26%
2026	14.5%	0.26%
2027	14.5%	0.26%
2028	14.5%	0.26%

The development of the weighted average fulfillment rates shown in Table A-7 are based on documented by-state RPS goals in certain key years of the Study Period, with the interim years reflecting a linear interpolation between the key years. Goals outlined for key years have been averaged with pre-existing goals already in place for states within each region, based upon a weighted average of states within each region. For MISO East, the states of Michigan (10% RPS by 2015), Illinois (25% RPS by 2025), Indiana (20% RPS by 2020), Missouri (13% by 2021 with 2.0% solar), and Ohio (12.5% RPS by 2025 with 0.5% solar) have RPS goals, while the other states that comprise a very small portion of the region do not currently have RPS goals, netting an average fulfillment rate in 2025 of approximately 14.75%, which includes a small portion of solar and is assumed to perpetuate into the future.

A.3 Market Module Results

A.3.1 Stochastic Gas Price Forecasts

The following graphs show the results of the 50 draws of the average annual gas prices from the Monte Carlo simulations of the regional model for the MISO East region. The bold black lines depict the 95th percentile values, expected values and 5th percentile values over the period 2009-2028.

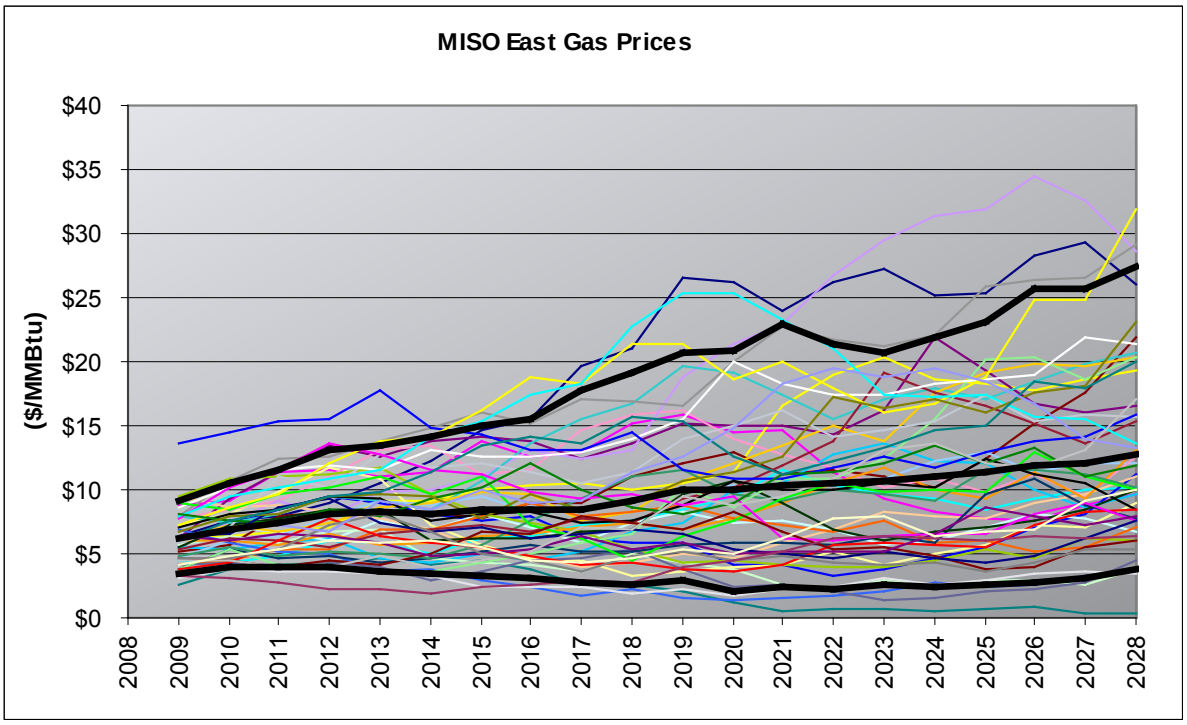

Figure A-2: MISO East Gas Prices

A.3.2 Stochastic Coal Price Forecasts

The following graphs show the results of the 50 draws of the average annual coal prices from the Monte Carlo simulations of the regional model for the MISO East region. The bold black lines depict the 95th percentile values, expected values and 5th percentile values over the period 2009-2028.

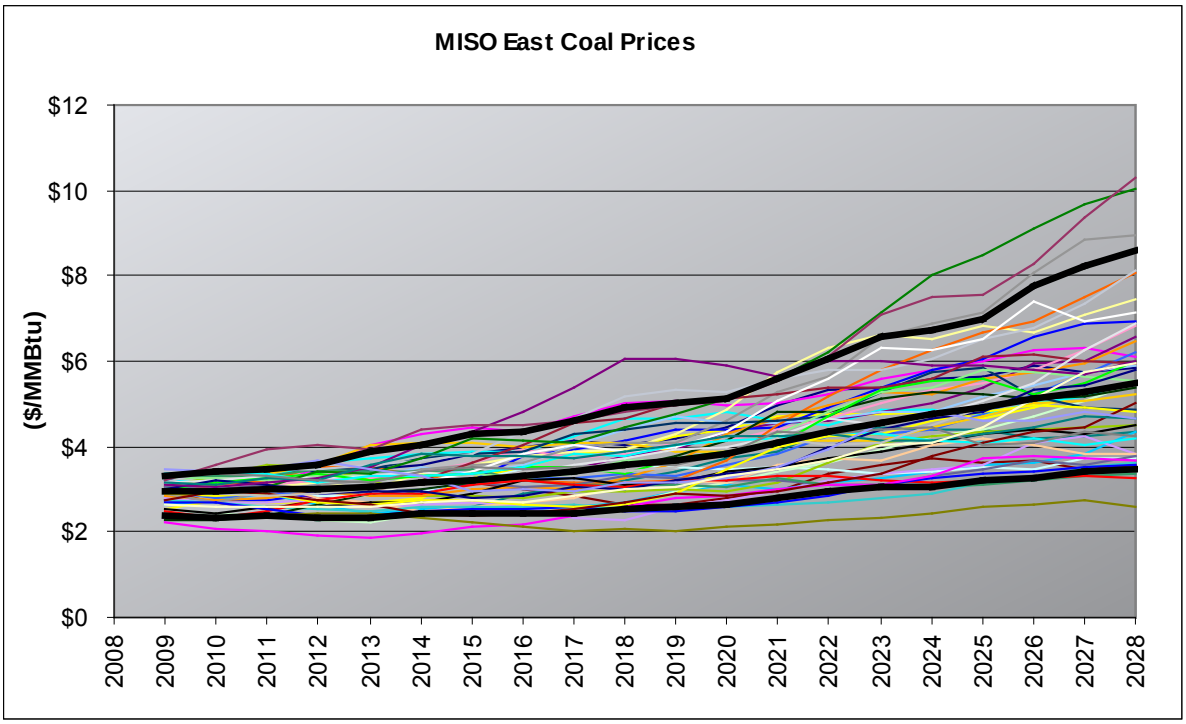

Figure A-3: MISO East Coal Prices

A.3.3 Stochastic Load Forecasts

MISO East Stochastic Load Forecast

The following graphs show the results of the 50 draws of the average annual on-peak and off-peak hourly load from the Monte Carlo simulations of the regional model for the MISO East region. The bold black lines depict the 95th percentile values, expected values and 5th percentile values over the period 2009-2028.

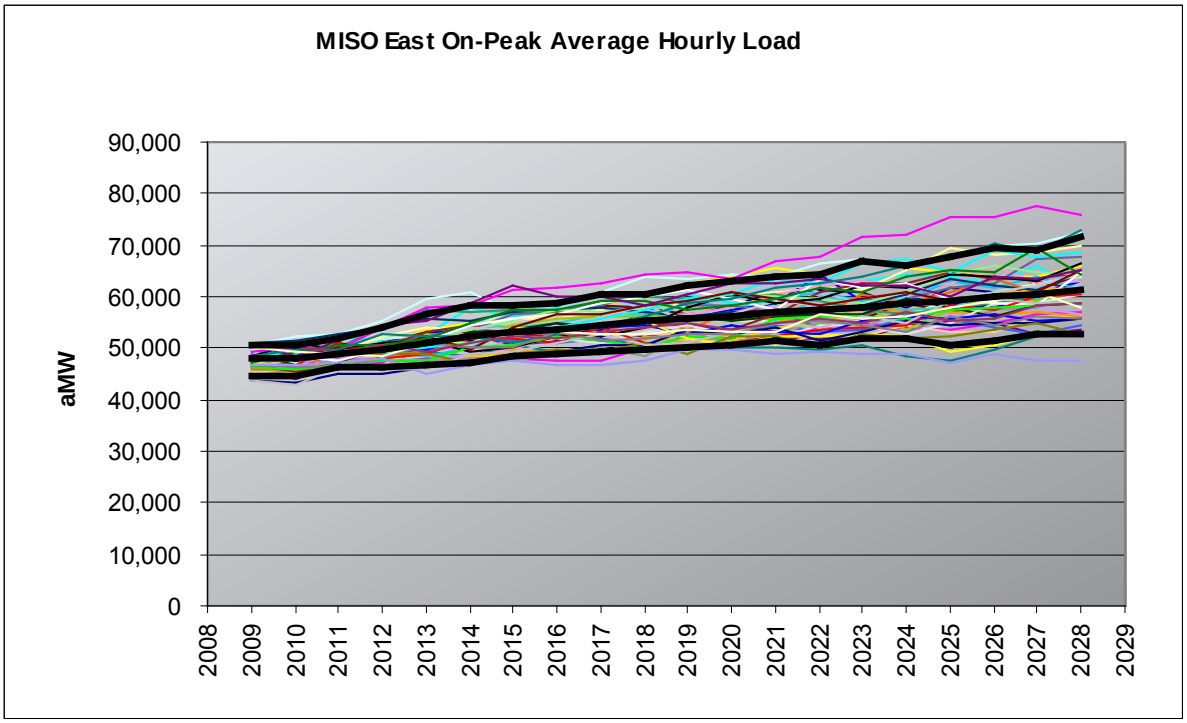

Figure A-4: MISO East On-Peak Average Hourly Load

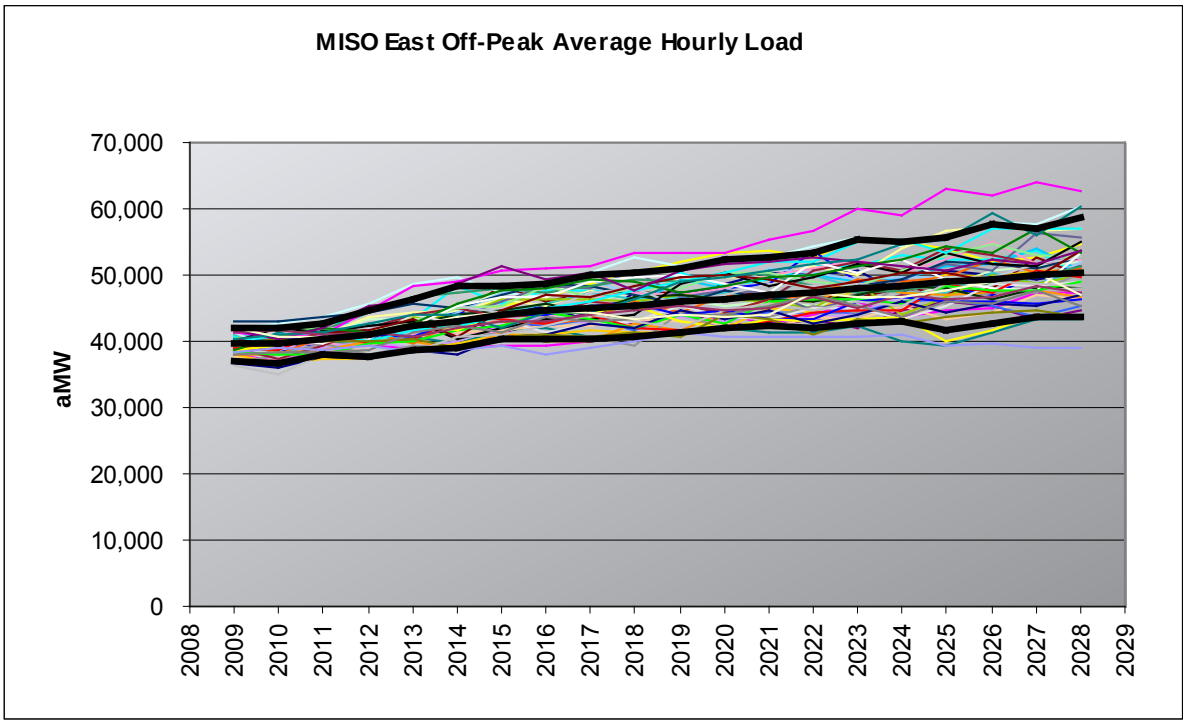

Figure A-5: MISO East Off-Peak Average Hourly Load

The following graph shows the projected average annual hourly load and the associated 95th percentile values and 5th percentile values over the period 2009-2028.

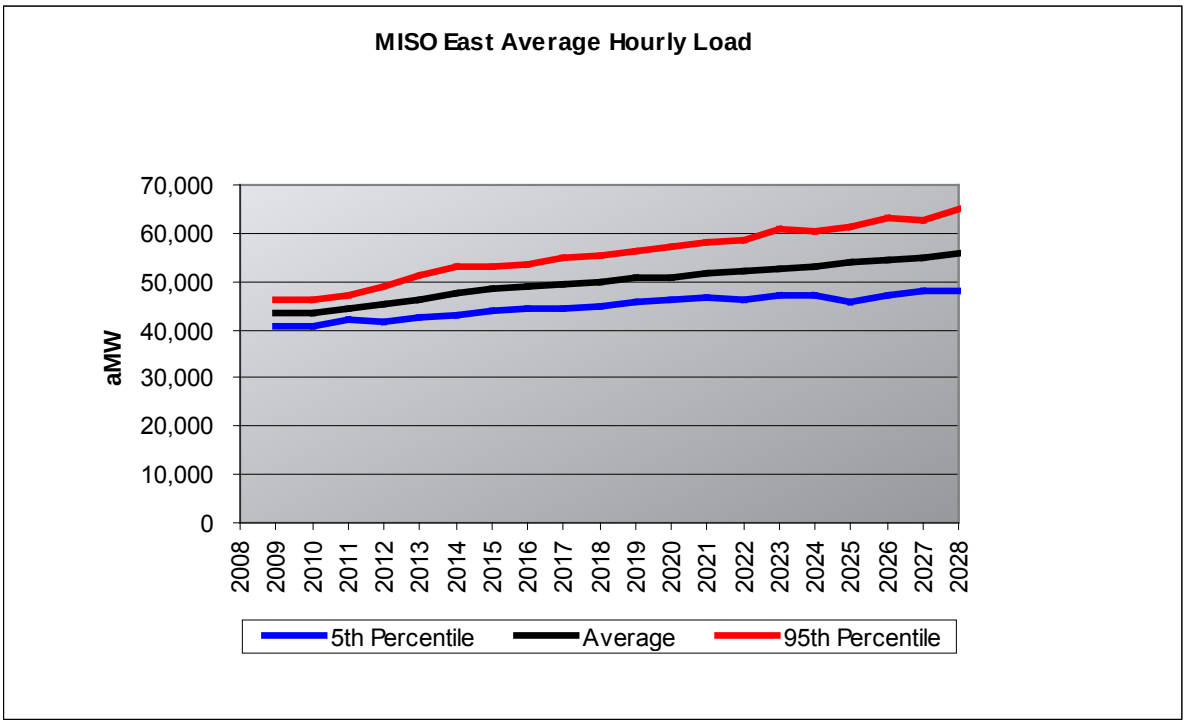

Figure A-6: MISO East Average Hourly Load

A.3.4 Projected Supply and Demand Balances

MISO EAST Projected Supply and Demand Balance

The Table A-8 shows the projected supply and demand balance over the term of the study period. The peak regional demand includes a 15% reserve margin. The table includes the average build-out of the generic resources over the 50 stochastic draws. Therefore, the capacity additions and retirements shown below reflect the average from the results of the 50 draws of the stochastic model. The projected supply and demand balance is shown graphically in Figure A-7.

Table A-8
MISO East Projected Demand and Expected Values for Additions and Retirements

	Peak Regional Load (MW)	Total Regional Capacity (MW)	Reserve Margin	Planned Additions/ Retire-ments	Economic Retire-ments	SCPC	G Class CC	F Class GT	H Class CC	IGCC with CCS	Nuclear
2009	73,932	87,611	18.50%	246	0	0	0	0	0	0	0
2010	74,157	88,680	19.60%	1,069	0	0	0	0	0	0	0
2011	75,676	89,097	17.70%	221	0	0	170	27	0	0	0
2012	76,923	88,962	15.70%	926	-1,591	0	362	168	0	0	0
2013	79,135	91,522	15.70%	1,527	-202	31	691	514	0	0	0
2014	80,735	93,300	15.60%	62	0	63	985	669	0	0	0
2015	82,338	95,237	15.70%	275	-34	172	962	561	0	0	0
2016	83,178	96,469	16.00%	85	-23	188	747	235	0	0	0
2017	84,249	97,912	16.20%	-77	-110	47	23	124	1,436	0	0
2018	85,240	99,556	16.80%	-89	-199	0	113	17	1,590	0	212
2019	86,173	101,005	17.20%	85	-234	0	0	0	1,334	0	265
2020	86,771	101,657	17.20%	-6	-617	0	0	10	975	0	291
2021	87,938	103,078	17.20%	-194	-661	16	0	77	1,813	0	370
2022	88,863	103,901	16.90%	-121	-621	31	0	27	1,163	0	344
2023	89,786	105,294	17.30%	-155	-640	31	0	0	1,813	0	344
2024	90,481	106,206	17.40%	-250	-879	188	0	44	1,385	0	423
2025	91,676	106,983	16.70%	-536	-940	78	0	81	1,590	0	503
2026	92,638	107,786	16.40%	-326	-978	0	0	134	1,471	0	503
2027	93,611	108,938	16.40%	-492	-465	16	0	101	1,436	0	556
2028	94,593	109,695	16.00%	-1,549	-172	125	23	175	1,573	0	582

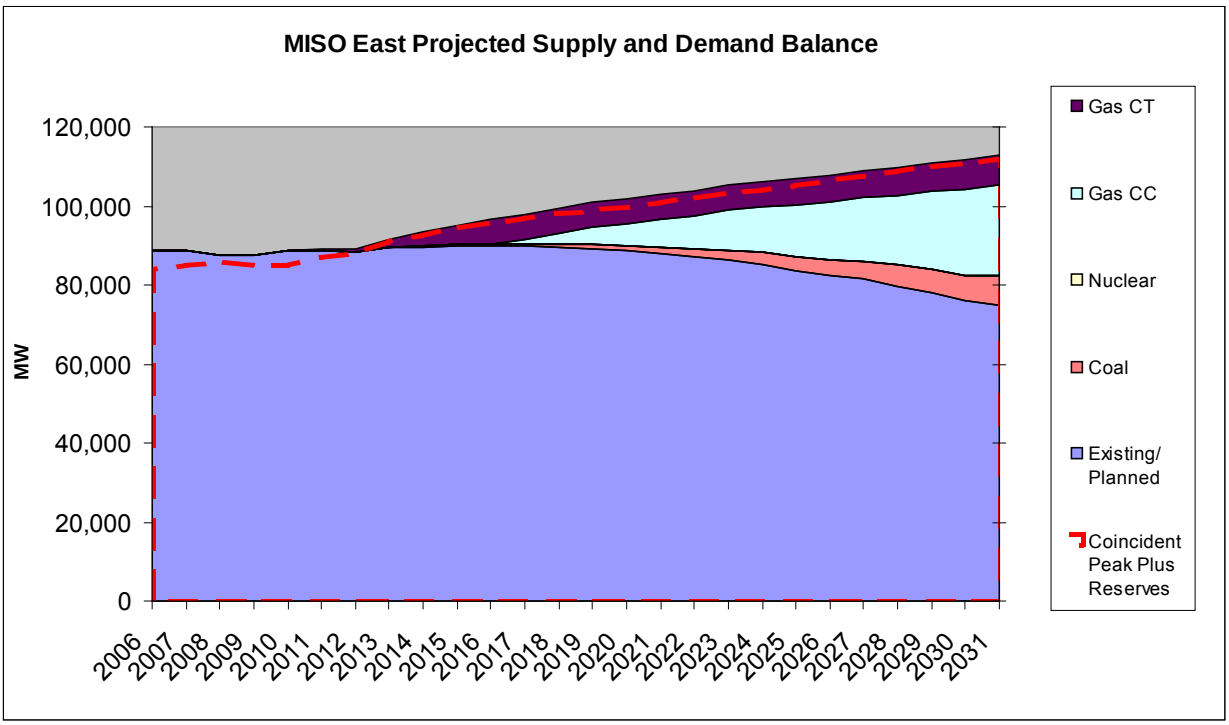

Figure A-7: MISO East Projected Supply and Demand Balance

A.3.5 Stochastic Power Price Forecasts

MISO EAST Stochastic Power Price Forecast

The following graphs show the results of the 50 draws of the average annual on-peak and off-peak energy prices from the Monte Carlo simulations of the regional model for the MISO East region. The bold black lines depict the 95th percentile values, expected values and 5th percentile values over the period 2009-2028.

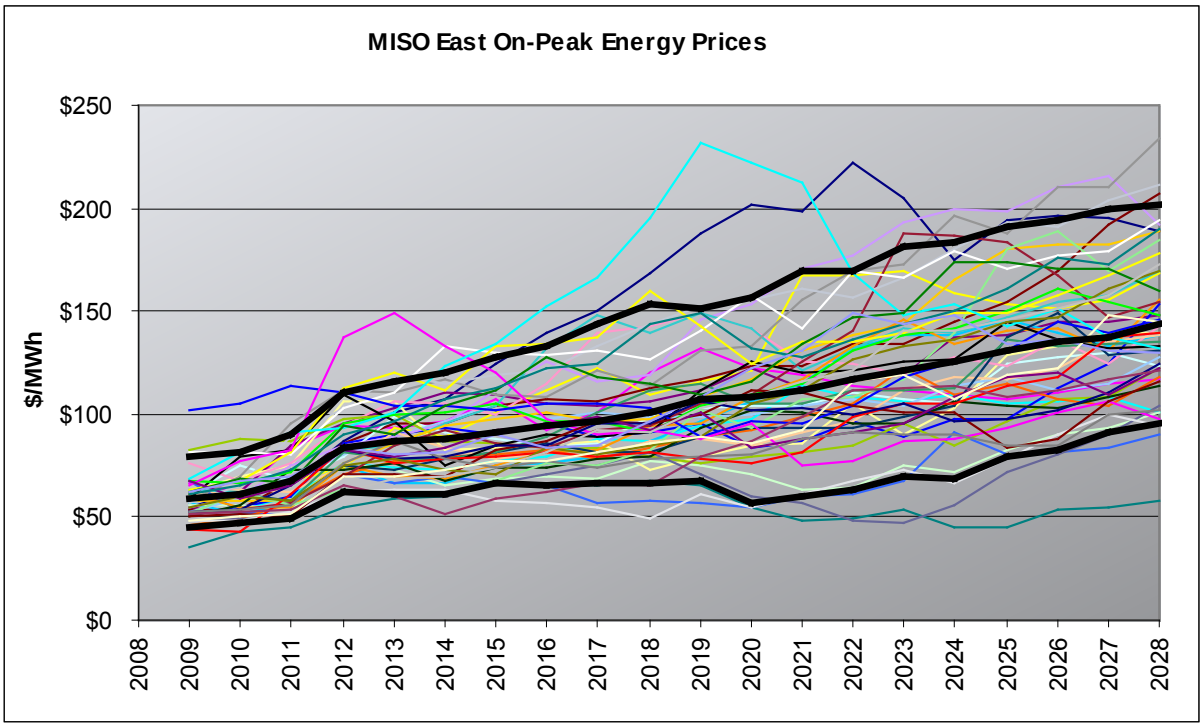

Figure A-8: MISO East On-Peak Energy Prices

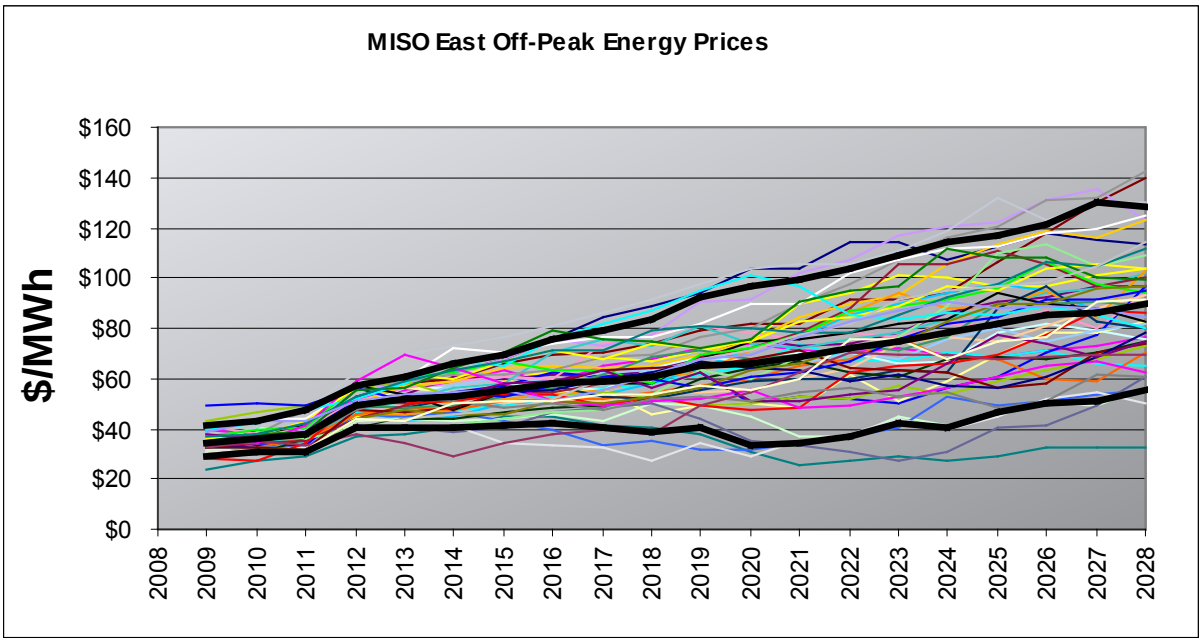

Figure A-9: MISO East Off-Peak Energy Prices

The following graph shows the projected average annual power price and the associated 95th percentile values and 5th percentile values over the period 2009-2028.

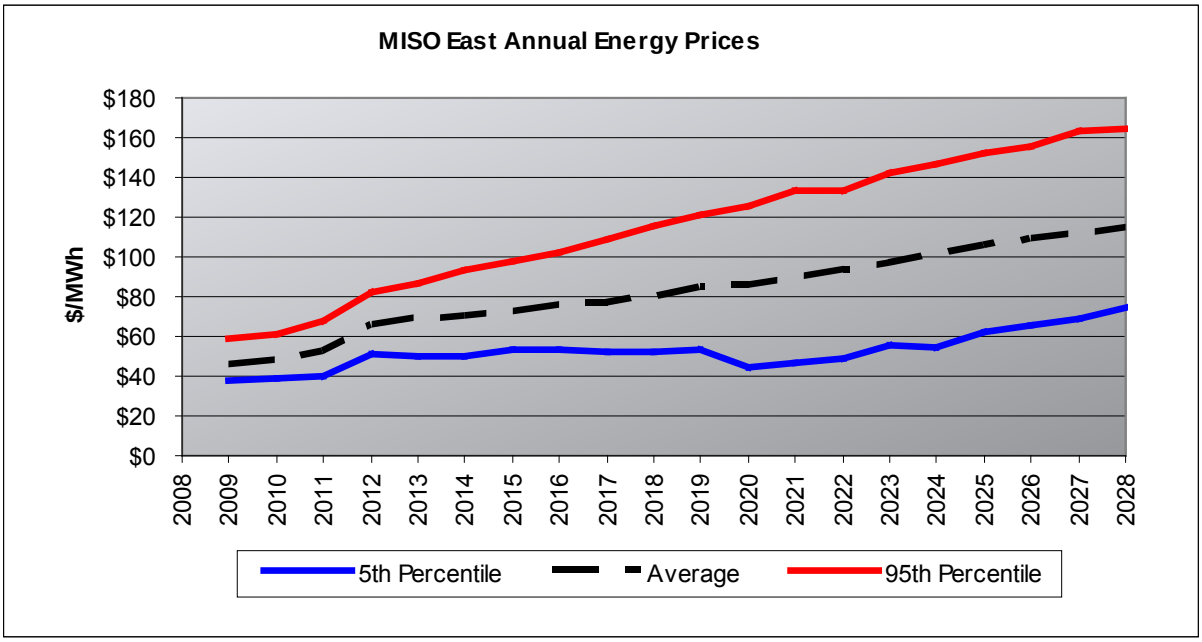

Figure A-10: MISO East Annual Energy Prices

The expected values of the on-peak, off-peak and average annual power price forecasts and the associated 95th percentile values and 5th percentile values for the average annual power price forecast over the period 2009-2028 are shown in the table below.

Table A-9
MISO East Expected Annual Energy Prices - $/MWh

Year	Average On-Peak	Average Off-Peak	Average Annual		
			Expected	5th %	95th %
2009	58.59	34.53	46.00	37.28	59.43
2010	61.47	36.03	48.16	39.06	61.40
2011	67.07	38.09	51.85	40.37	67.79
2012	83.98	49.39	65.84	50.98	82.30
2013	87.17	51.63	68.57	50.31	86.86
2014	87.50	53.18	69.54	50.47	93.53
2015	91.19	55.45	72.49	53.40	97.41
2016	94.28	57.66	75.07	53.37	101.83
2017	96.95	59.19	77.12	52.61	109.31
2018	100.46	60.95	79.79	52.07	115.63
2019	107.10	64.65	84.89	53.54	120.83
2020	108.22	65.81	86.05	44.43	125.59
2021	111.63	68.60	89.11	46.83	133.56
2022	117.42	72.09	93.61	49.25	132.94
2023	121.50	75.10	97.14	55.21	142.06
2024	125.23	78.15	100.62	54.11	146.34
2025	130.70	82.18	105.31	62.40	152.02
2026	135.24	85.39	109.16	66.08	155.55
2027	137.46	86.32	110.70	69.23	162.79
2028	143.37	89.33	114.92	74.19	163.92

The expected values of the annual capacity prices and average annual power price (including the capacity component) are shown in the table below.

Table A-10
MISO East Expected Annual Power Prices

Year	Capacity Price ($/kW-yr)	Average Power Price ($/MWh)
2009	0.00	46.00
2010	0.00	48.16
2011	10.85	54.33
2012	48.57	76.72
2013	48.99	79.60
2014	43.79	79.38
2015	51.62	84.08
2016	33.34	82.55
2017	23.31	82.38
2018	18.87	84.07
2019	21.21	89.72
2020	11.30	88.61
2021	30.08	95.96
2022	19.48	98.04
2023	21.52	102.04
2024	20.48	105.27
2025	33.70	112.95
2026	35.32	117.14
2027	34.43	118.48
2028	39.10	123.71

Appendix B
BIOMASS FUEL SUPPLY ANALYSIS

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An SAIC Company

Appendix B
BIOMASS FUEL SUPPLY ANALYSIS

R. W. Beck, Inc. was retained by Traverse City Light and Power (TCLP) to conduct a power supply resource planning study (IRP Study), including developing reasonable projections of the cost of biomass feedstock as renewable fuel. TCLP plans to develop small-scale biomass-fueled steam generating units to be located within its service area and adjacent to potential industrial plants that might make use of a portion of each unit's steam output (i.e., cogeneration). Such renewable generation would provide TCLP both local generation, which could secure more reliable power supply than distant generation and save transmission costs, and would help fulfill the renewable generation goals of TCLP and standards recently enacted by the State of Michigan.

R. W. Beck reviewed information on biomass fuels from the Department of Energy[1], National Renewable Energy Laboratories (NREL)[2], the Department of Agriculture[3], and the Forestry Products Laboratory (FPL)[4]. From those sources, information was developed related to supply, demand, and price for multiple types of biomass fuels. According to our research, biomass is typically collected within 50 to 100 miles of where it is consumed. The most abundant fuel sources within 100 miles of Traverse City (the "Local Area") consist of agricultural residues (AGR), forest residues (FR), mill and urban waste (MUW), and switch grass (SWG). The existing utility-scale generating plants in the Local Area use only wood or wood waste solids. As demand for these fuels increases, prices are expected to rise, which allows for higher priced biomass sources to enter the mix. For the purposes of this analysis, all of the above-listed biomass fuels were included in order to account for the impact of increasing regional demand on pricing and the resulting substitution between preferred biomass fuel sources.

B.1 Cost Components: Commodity

There is very limited public information available related to the costs of biomass, particular beyond the regional or state level. Consequently, assumptions for costs are based on widely-accepted research papers and public sources, including those from, but not limited to, NREL[5], ORNL[6], the DOE[7] and the FPL[8]. The reported cost for each biomass supply source is at the delivery point, but was reported during different years for each fuel type. Consequently, the analysis uses the Bureau of Labor

[1] Department of Energy (DOE), < http://www.eia.doe.gov/fuelrenewable.html >
[2] National Renewable Energy Laboratories (NREL), <http://www.nrel.gov/ >
[3] U.S. Department of Agriculture, National Agricultural Statistics Service, < http://www.nass.usda.gov/#>
[4] Forest Products Laboratory (FPL), < http://www.fpl.fs.fed.us/ >
[5] ibid
[6] ibid
[7] ibid
[8] ibid

Statistics price index for logging and pulpwood to normalize the costs of each fuel type to 2008 dollars. R. W. Beck's general inflation assumption of 2.4% is embedded in the annual forecast, but we have also considered other demand-side factors, which would impact future prices of the commodity, namely those related to fulfillment of the renewable portfolio standard (RPS) goals outlined in recent legislation enacted by the State of Michigan.

B.2 Cost Components: Demand

Table B-1 lists existing biomass generation resources in the Local Area, which utilize a mix of wood and wood-waste solids (WDS) fuel sources. For the scope of this analysis, we have only identified the local competition for biomass sources as generating plants with an operating or planned unit status and have not included other competing uses for the fuel that may arise due to new standards for renewable resources. Furthermore, we have not identified the specific fuel classified under WDS, but a mix of paper pellets, railroad ties, wood chips or forest residues would generally be classified as WDS. This is consistent with standard classification systems used by NREL and Oakridge National Laboratories (ORNL). The analysis assumes that the existing plants will compete for the same biomass supply resources as the TCLP's planned projects (5-10 MW installations totaling up to 30 MW over the study period). New capacity is assumed to operate at an 80% capacity factor (CF). Steam and hot-water production for resale are not included in this analysis.

Table B-1
Existing Local Area Biomass Generation

Plant Name	County	Capacity (MW)	Average Heat Rate (MMBtu/MWh)
Cadillac Renewable Energy	Wexford	39.6	17.69
Grayling (MI)	Crawford	36.2	14.34
Hillman Power Co LLC	Montmorency	17.8	14.55
Viking Energy of Lincoln	Alcona	16	12.93
Viking Energy of McBain	Missaukee	18	14.49

Existing generating resources in the Local Area comprise a total of 127.6 MW with a weighted average heat rate of 15.1 MMBtu/MWh. The heat content of the fuel sources is based on dry weight and varies from 14.6 to 17.3 MMBtu/dry ton (See Table B-2). Based on the average energy (MWh) production of the generating plants listed in Table B-1, between the years 2006 and 2008 we assessed the current demand for biomass fuel in the Local Area to be between 785 and 800 GWh per year. Using the weighted average heat rates of the facilities and the weighted average heat content of biomass at different penetration levels we were able to determine the level of biomass required to support electric generation in the region. Hence, the current demand for biomass used in the Local Area utility power plants is approximately 726,672 dry tons annually.

Table B-2
Assumptions Used in the Analysis

	Urban Waste	Mill Wastes	Forest Residues	Agricultural Residues	Switchgrass
Dry tons per annum	86,733	606,463	482,830	397,149	697,351
Heat Content (MMBtu/ Dry Ton	17.3	17.3	17.3	14.6	14.7
Local Area Heat Rate (MMBtu/MWh)			15.07		

B.3 Cost Components: Transportation

In addition to commodity costs, transportation represents a significant portion of the delivered costs of biomass. In the original analysis conducted by Walsh[9], hauling cost was estimated as $0.1 per ton-mile. This value is also supported by reports published by the DOE[10] and the Office of Energy Policy[11], whereby transport cost is defined as the cost of fuel, maintenance, and capital cost associated with using a truck or tractor to move biomass from a point of origin to a point of use. We estimated that the transport cost[12] is $0.14 per ton-mile in 2008 dollars. Given that biomass feedstock availability is only assessed periodically by public research centers, it is reasonable to expect that the underlying transportation costs would have an even greater share of the total commodity costs in the future. Consequently, we utilized Cost Analyzer[13] to project future transport costs. Because transportation is a major portion of the cost, supply sources from the Upper Peninsula were not considered.

[9] Walsh, Biomass Feedstock Availability in the United States: 1999 State Level Analysis
[10] Haq, Zia, Biomass for Electricity Generation. Energy Information Administration
[11] Gallagher, Paul, Biomass from Crop Residues: Cost and Supply Estimates. U.S. Department of Agriculture, Office of the Chief Economist, Office of Energy Policy and New Uses. Agricultural Economic Report No. 819
[12] Bureau of Labor Statistics PPI for General Freight & Trucking
[13] IHS Global Insight Cost Analyzer

Table B-3
General Freight & Trucking Cost

Year	Annual Escalation	Cost $/ton-mile
2008	0.0	0.140
2009	-2.0%	0.137
2010	2.0%	0.140
2011	6.0%	0.148
2012	6.6%	0.158
2013	5.3%	0.167
2014	4.2%	0.174
2015	3.2%	0.179
2016	3.1%	0.185
2017	3.0%	0.190
2018	2.9%	0.196
2019	3.6%	0.203
2020	2.8%	0.209
2021	3.4%	0.216
2022	3.2%	0.223
2023	3.1%	0.230
2024	3.0%	0.237
2025	3.0%	0.244
2026	3.4%	0.252
2027	2.8%	0.259
2028	3.2%	0.267

B.4 Supply Curve

The final step to developing a price forecast involved the development of an integrated supply curve ($2009) for the local area based on our assessment of current market conditions. The supply curve is a representation of the incremental costs of delivering biomass fuel to a proposed generating station within Traverse City. An integrated supply curve captures the total quantities from the supply curves for each source of biomass (i.e. FR, AGR, MUW, and SWG) to account for substitution effects between the fuel sources at increasing levels of demand. Hence, as one source of fuel becomes more expensive relative to the others, it is substituted with a cheaper source.[14] Figure B-1 shows the integrated supply curve for the combined biomass fuel sources.

[14] Although, we have shown the supply curve in $/Dry ton for delivery costs, to illustrate substitution effects $/MMBtu may provide a more accurate representation since the heat content is different for each fuel source. Consequently, substitution will likely be based on $/MMBtu and variations in the fuel

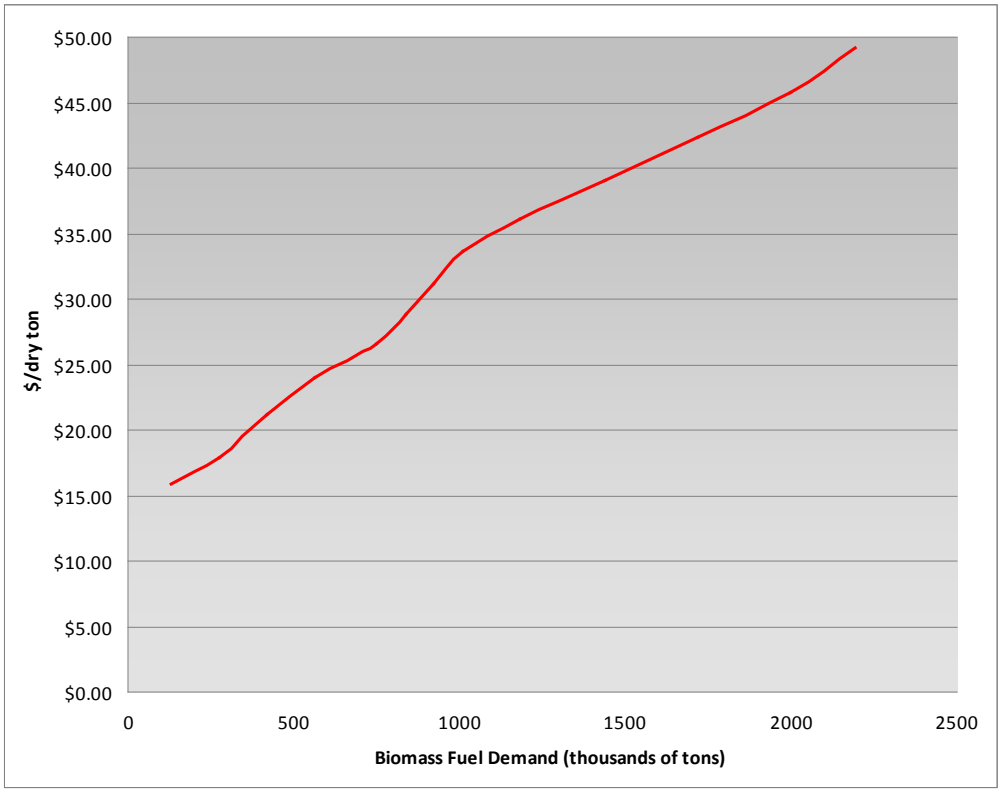

Figure B-1. Local Area Biomass Supply Curve (2009$)

B.5 Cost Components: Renewable Portfolio Standards

The state-mandated RPS will drive continued growth in demand for renewables. According to the RPS, load serving entities must serve 10% of their retail sales through renewables by 2015. Utilities can meet the objective by purchasing renewable energy credits (REC's), advanced cleaner energy credits (ACEC's), executing purchase power agreements (PPA's) or through expansion of their own renewable generation capacity. In 2007, total retail sales of electricity in Michigan were 98,842 GWh, including sales from public utilities, municipal utilities and cooperatives. Retail sales from qualifying RPS facilities totaled 1,837 GWh, approximately 1.86% of the state total. In order to meet the 2015 objective, the state plans to have enough installed renewable capacity to serve 2.0% of retail sales by 2012, 3.3% of retail sales by 2013, 5.0% by 2014, and 10% of retail sales by 2015 (based on the requirements in P.A. 295).

processing costs at the generating facility. For this analysis, we have assumed that processing is uniform for each fuel source.

Consumers Energy (CE) and Detroit Edison (DTE) serve more than 90% of the retail customers in Michigan; thus the two utilities will also drive most of the new demand for renewable resources. The service territory for CE includes most of the Lower Peninsula while DTE's territory consists primarily of eastern Michigan. According to recent press releases and the renewable energy plans submitted by both utilities, CE and DTE plan to heavily invest in new wind projects either through acquisition of RECs, building new plants, or through executing PPAs. Specifically, DTE plans approximately $3.9 billion of expenditures to purchase renewable energy from Michigan-based facilities through 2029. The resource mix will consist primarily of wind and may also include landfill gas, biomass, solar, hydropower, and other sources approved by the Michigan Public Service Commission. CE stated that it would need 4 million MWh to meet its RPS objective. Of the 4 million MWh, 2.5 million MWh are expected to come from wind generation, and the remainder from other sources.

For the purpose of this study, we assumed that new biomass facilities would constitute no more than 10% of the RPS requirement. We also assumed that the largest utilities will distribute installation of biomass facilities throughout their service area in order to avoid transmission congestion and to not put upward price pressure on local feedstock sources.

Assumptions in model:

- New facilities will be distributed throughout the state based on the percentage of statewide biomass feedstock (dry tons) available in the Local Area and by proximity to load centers.
- Growth in retail load will be approximately 1.43% annually over the forecast horizon.
- Transmission congestion will potentially make utilities want to distribute their generation facilities throughout the region so as not to incur costs of building new transmission and to avoid congestion.
- Lack of available feedstock will force utilities to distribute generation facilities as long as there are transmission alternatives.
- CE and DTE will account for most of the demand for biomass, landfill gas and wind resources.
- On a state level the effect of demand for RECs and PPAs will also make development of new biomass generation facilities distributed, as developers will build where the fuel source is cheapest. Utilities will be able to purchase RECs from these facilities. For example, according to DTEs Renewable Energy Plan, 56% of their renewable portfolio will be composed of PPAs and REC and ACEC purchases.

Factors not modeled:

(1) As demand increases, the proportion of biomass delivered costs due to transportation may decrease. However, transmission congestion may affect the

interconnection of facilities as new generation is more remote from the load centers. Consequently, the value of biomass feedstock in certain locations will be impacted by network constraints.

B.6 Price Forecast Results

Table B-4 shows the estimated annual amount of electric generation from renewable resources that are required to meet the RPS. After 2015, additional renewable generation is still necessary, but the growth rate will follow the rate of load growth.

Table B-4
Annual Renewable Generation Requirements (MWh)[15]

	RPS Requirement	Generation from Renewable Resources	Generation from Biomass Resources		
			10% of Requirement	40% of Requirement	50% of Requirement
2009	0.0%	0	0	0	0
2010	0.0%	0	0	0	0
2011	0.0%	0	0	0	0
2012	2.0%	2,122,169	212,217	848,868	1,061,085
2013	3.3%	3,551,613	355,161	1,420,645	1,775,807
2014	5.0%	5,458,124	545,812	2,183,250	2,729,062
2015	10.0%	11,072,230	1,107,223	4,428,892	5,536,115
2016	10.0%	11,230,440	1,123,044	4,492,176	5,615,220
2017	10.0%	11,390,911	1,139,091	4,556,364	5,695,456
2018	10.0%	11,553,675	1,155,367	4,621,470	5,776,837
2019	10.0%	11,718,765	1,171,876	4,687,506	5,859,382
2020	10.0%	11,886,213	1,188,621	4,754,485	5,943,107
2021	10.0%	12,056,054	1,205,605	4,822,422	6,028,027
2022	10.0%	12,228,323	1,222,832	4,891,329	6,114,161
2023	10.0%	12,403,052	1,240,305	4,961,221	6,201,526
2024	10.0%	12,580,279	1,258,028	5,032,111	6,290,139
2025	10.0%	12,760,037	1,276,004	5,104,015	6,380,019
2026	10.0%	12,942,364	1,294,236	5,176,946	6,471,182
2027	10.0%	13,127,297	1,312,730	5,250,919	6,563,649
2028	10.0%	13,314,872	1,331,487	5,325,949	6,657,436

The delivered price of biomass fuel will be dependent on the proportion of renewable generation due to power generation from new biomass facilities. As more biomass-

[15] The values listed in the table correspond to requirements. Annual electricity generation during the period 2006 through 2008 from biomass in Michigan is estimated at approximately 800,000 MWh.

fueled power plants are installed through time and certain types of existing coal-fired plants are retro-fitted to burn the fuel, the cost of biomass fuel can be expected to increase. Table B-5 shows the projected commodity and transportation costs of biomass fuels delivered to the TCLP area assuming 10% of the projected renewable energy requirement is met with biomass resources.

Table B-5
Biomass Price Forecast At 10% of Renewable Energy Requirement Provided From Biomass Resources

	Demand	Feedstock Costs		Transportation Costs		Biomass Price Forecast	
	(Dry Tons)	(Current $/Dry Ton)	(Nominal $/Dry Ton)	(Current $/Dry Ton)	(Nominal $/Dry Ton)	(Nominal $/Dry Ton)	$MMBTu*
2008	708,021	$19.08	19.08	$7.44	$7.44	$26.52	$1.57
2009	708,021	$19.08	19.54	$7.44	$7.28	$26.82	$1.59
2010	731,135	$19.35	20.29	$7.49	$7.47	$27.76	$1.64
2011	761,329	$19.87	21.34	$7.56	$8.02	$29.35	$1.74
2012	792,373	$20.64	22.69	$7.62	$8.62	$31.32	$1.85
2013	824,286	$21.43	24.13	$7.68	$9.15	$33.28	$1.97
2014	859,273	$22.30	25.71	$7.76	$9.60	$35.31	$2.09
2015	893,011	$23.13	27.31	$7.86	$10.03	$37.34	$2.21
2016	896,180	$23.21	28.06	$7.87	$10.35	$38.41	$2.27
2017	899,394	$23.29	28.83	$7.88	$10.70	$39.53	$2.34
2018	902,655	$23.37	29.62	$7.89	$11.06	$40.68	$2.41
2019	905,962	$23.45	30.44	$7.90	$11.42	$41.86	$2.48
2020	909,316	$23.54	31.29	$7.91	$11.81	$43.10	$2.55
2021	912,718	$23.62	32.15	$7.92	$12.20	$44.35	$2.62
2022	916,169	$23.71	33.05	$7.93	$12.60	$45.65	$2.70
2023	919,669	$23.79	33.95	$7.94	$13.02	$46.98	$2.78
2024	923,219	$23.88	34.90	$7.95	$13.46	$48.36	$2.86
2025	926,820	$23.97	35.87	$7.96	$13.90	$49.78	$2.94
2026	930,472	$24.06	36.87	$7.97	$14.37	$51.24	$3.03
2027	934,176	$24.15	37.90	$7.98	$14.85	$52.74	$3.12
2028	937,934	$24.25	38.97	$7.99	$15.34	$54.31	$3.21

* Conversion from $/Dry Ton to $/MMBtu assumes heat content of approximately 8,500 Btu/lb.

Appendix C
STOCHASTIC ECONOMETRIC REGIONAL FORECASTING MODEL

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Appendix C
STOCHASTIC ECONOMETRIC REGIONAL FORECASTING MODEL

C.1 Overview of Model

For the IRP Study, the R. W. Beck proprietary Stochastic Econometric Regional Forecasting ("SERF") model was used. The SERF model generates stochastic projections of fuel prices, electric loads for the region and the subject utility (in this case TCLP), emission prices, and power prices. The model simulates corresponding utility power supply costs for multiple potential resource expansion portfolios based on the stochastic projections. A stochastic dynamic programming algorithm determines the optimal resource expansion decisions. The general structure of the SERF model is depicted below in Figure 5-1.

SERF consists of three primary modules:

- Stochastic Market Module, which generates stochastic projections of fuel, power prices, utility loads, and emission prices and simulates the build-out and commitment/dispatch of market resources;
- Production Cost Module, which simulates a utility's generating resource commitment and dispatch; and
- Stochastic–Dynamic Optimization Module, which determines a utility's optimal generation expansion plan given uncertain load and market and commodity price conditions.

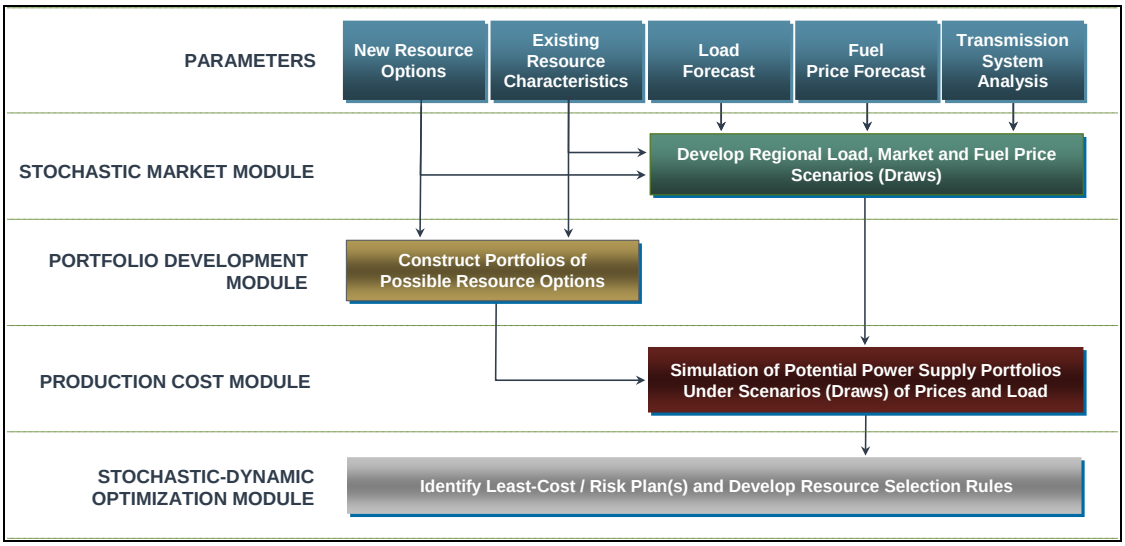

Figure C-1: SERF Model Overview

The discussion in the following sections describes each of the modules.

C.1.1 Stochastic Market Module

The Stochastic Market Module was used to simulate market conditions and power prices for the MISO East and surrounding market regions. The Stochastic Market Module works in the following manner.

- Step 1: For a given number random paths of future uncertain conditions, for each simulated region, and for each year of the study period, the module generates stochastic projections of hourly loads, daily gas prices, monthly coal prices, and hourly hydroelectric generation. The stochastic projections reflect several important correlations, including those among fuels, those for load across the simulated regions, and those for load between the regions and the subject utility.
- Step 2: For each random path and hour, a multi-area dispatch algorithm is used to calculate the marginal cost of power in each region. This algorithm dispatches available generating capacity to meet the load projected in Step 1 in all modeled regions at the lowest possible cost, taking into account fuel prices and hydroelectric generation projected in Step 1, and the operating characteristics of the available capacity (e.g., capacity rating, heat rate, variable O&M cost, emissions costs).
- Step 3: Stochastic equations relating the power price to the marginal cost are used to generate projections of hourly electric prices for each random path, hour, and region, using the marginal cost projections from Step 3.
- Step 4: For the initial years of the study period, and for all paths, the capacity available for dispatch in Step 2 is comprised of the existing fleet of plants, less planned retirements, plus planned additions. Thereafter, the available capacity varies across paths, and is determined in the following manner.
- In processing each random path, the module considers at the beginning of each year the possible capacity additions for the path multiple years into the future (reflecting generation expansion decisions that must be made prior to the date of actual need). The module then simulates a given number of secondary random paths of regional loads, fuel prices, hydroelectric generation, marginal power costs, and power prices prior to the on-line date of potential new resources to simulate potential resource decisions given the level of uncertainty that exists at the time the resource expansion decision must be made.
- The algorithm calculates the market value from the secondary draws as of the on-line date for each potential generating resource alternative. If one or more of the alternatives has positive expected profits, the algorithm builds the resource and adds it to the regional market stack for that primary path. The algorithm iterates until planning reserve requirements are met and no more profitable resource additions can be made.
- Once the algorithm has determined the capacity additions for the primary path for a particular future year, the module simulates loads and prices for the path for the decision year and then repeats the capacity expansion decision process

for each subsequent year for each primary random path until the end of the study period is reached.

- Through this process, the algorithm constructs a generation expansion plan for each primary path by simulating resource expansion decisions prior to the actual on-line dates of potential resources given uncertain market conditions (i.e., simulating real world decision-making processes).

The equations used to generate projections of loads, fuel prices, hydroelectric generation, and power prices are stochastic in nature and include both (i) parameters that describe the *expected* evolution of the variable over time and (ii) parameters that describe the *volatility* of the variable over time. The parameters of these equations are estimated econometrically, using available historical data.

The equations for loads, fuel prices, and hydroelectric generation are all univariate. In other words, the expected value of a variable depends on the previous values of the variable, time, and random disturbances, but not the values of the other variables. For loads, the process for simulating hourly values is processed as three separate but linked stages: an equation for annual loads, an equation for monthly loads (conditional on the annual load), and an equation for hourly loads (conditional on the monthly loads). Similarly, the equations for daily natural gas prices is modeled as separate (but linked) annual, monthly, and daily equations; and the monthly equations for coal prices, as linked annual and monthly equations. For loads and fuel prices, monthly, daily, and hourly volatilities are treated as time varying, with a Generalized Autoregressive Conditional Heteroskedasticity (GARCH) structure.

The expected power price and its volatility in a market region and hour is a function of the simulated marginal cost in the region by hour and the relationship of load to capacity in the region. The parameters of these equations are estimated by simulating historical marginal costs or market prices from the multi-region dispatch algorithm, and econometrically analyzing the resulting simulated costs together with actual price, load, and capacity data.

C.1.2 Production Cost Module

The Production Cost Module is a standard market-based chronological commitment and dispatch algorithm. For each random path and potential portfolio of resource alternatives, the algorithm works in the following manner.

- Resources are committed and dispatched as required to serve load and initiate sale of power to the market at the projected hourly power prices developed by the Stochastic Market Module, taking into account projected monthly/daily fuel prices and the operating characteristics of the generating units in a portfolio (e.g., capacity ratings, minimum up and down times, startup costs, non-linear heat-rate curves, etc.). The algorithm determines the amount of power to generate for load and sell in each hour (up to user-specified quantity limits) by determining the output that would minimize net production costs for the year.

- Power can be purchased from the market to satisfy the utility's projected hourly loads at the projected hourly power prices when such purchases are lower costs that self-generation (and within user-specified quantity limits).
- The total net production cost for each random path, year, and portfolio is computed as the sum of costs of generation and market purchases, less market sales revenue.

C.1.3 Stochastic Dynamic Optimization Module

The Stochastic Dynamic Optimization Module works in the following manner.

- For the purpose of making investment decisions, three variables are considered to be stochastic: the utility's annual average load, the average annual natural gas price, and the average annual market-implied heat rate (i.e., the average power price divided by the average natural gas price). For each year of the study period, the probability distribution of each of these four variables is determined, and the value of each variable at user-defined percentiles (e.g., 10th, 30th, 50th, 70th, and 90th) is calculated. Each possible combination of the three stochastic variables and percentiles is referred to as an "Evaluation Point."
- The algorithm works backward through time (starting at the end of the study period), evaluating the best capacity expansion decisions that can be made for a future year (i.e., the decision must be made prior to the on-line date). The algorithm makes a separate decision for (i) each of the possible Evaluation Points and (ii) each possible prior year investment decision.
- In each year, the algorithm performs the following steps:
  - For each Evaluation Point, the algorithm calculates the expected value of each of the three stochastic variables in the installation year, as well the variance of each variable. For each possible portfolio in the installation year, the algorithm combines these expected values and variances with the results from the Production Cost Module to calculate the expected value and variance of annual production costs and fixed costs for the portfolio.
  - For each Evaluation Point and potential prior year decisions, the algorithm identifies the portfolios that best satisfies the decision criterion and is feasible (satisfies utility-specific planning requirements and represents a possible portfolio given subsequent year decisions). At each decision point, the algorithm can use either of two decision criteria: select the portfolio with the lowest expected value of future total system costs or select the portfolio with the lowest risk, or exposure.
- Continuing to move backward through time, the algorithm addresses the decisions to be made in prior years in much the same manner, but also giving consideration to the set of possible portfolios for a given random path that contain resource alternatives that were already identified as least cost alternatives in later years of the study. This process continues until the first year

of the study period is reached and the lowest-cost or least risk plan can be readily identified.

Appendix D
POWER SUPPLY PLAN RESULTS

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Table D1.1

Traverse City Light & Power

Resource Plan - Annual

Existing Resources

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Peak Demand (MW)										
Peak Demand	74.9	75.1	74.9	75.5	77.2	77.5	77.5	78.3	78.7	79.1
Reserves	11.2	11.3	11.2	11.3	11.6	11.6	11.6	11.7	11.8	11.9
Capacity Requirements	86.1	86.4	86.1	86.8	88.8	89.2	89.1	90.0	90.5	90.9
Capacity Resources (MW)										
Existing Resources										
Belle River	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Campbell 3	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Kalkaska CT	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9
Existing Wind*	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Granger Landfill Gas	0.3	0.8	0.9	1.4	1.4	1.7	1.7	1.7	1.7	1.7
Total	58.1	58.6	58.7	59.3	59.3	59.5	59.5	59.5	59.5	59.5
Future Resources										
SCP Coal wCCS	-	-	-	-	-	-	-	-	-	-
Combined Cycle	-	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	-	-	-	-	-	-	-
Heritage Wind*	-	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
New Solar	-	-	-	-	-	-	-	-	-	-
TCLP Biomass	-	-	-	-	-	-	-	-	-	-
Market Purchases	28.1	27.0	26.6	26.8	28.7	28.9	28.8	29.7	30.2	30.6
Total	28.1	27.8	27.4	27.6	29.5	29.7	29.6	30.5	31.0	31.4
Total Capacity	86.1	86.4	86.1	86.8	88.8	89.2	89.1	90.0	90.5	90.9
Surplus/(Deficiency)	-	-	-	-	-	-	-	-	-	-
Energy from Renewable Resources	0.9%	8.1%	8.5%	9.7%	9.4%	10.0%	9.9%	9.8%	9.8%	9.7%
State REP Requirement	0.0%	0.0%	2.0%	3.3%	5.0%	10.0%	9.9%	9.9%	9.8%	9.7%
TCLP RPS Goal	0.0%	0.0%	2.0%	3.3%	5.0%	10.0%	10.0%	10.0%	10.0%	10.0%

* Reflects a capacity credit for resource adequacy purposes of 8% of nameplate capacity per the currently proposed MISO default standard.

Table D1.1

Traverse City Light & Power

Resource Plan - Annual

Existing Resources

	2020	2021	2022	2023	2024	2025	2026	2027	2028
Peak Demand (MW)									
Peak Demand	79.1	80.0	80.5	81.0	81.0	82.0	82.6	83.2	83.2
Reserves	11.9	12.0	12.1	12.1	12.1	12.3	12.4	12.5	12.5
Capacity Requirements	91.0	92.0	92.5	93.1	93.1	94.3	95.0	95.7	95.7
Capacity Resources (MW)									
Existing Resources									
Belle River	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Campbell 3	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Kalkaska CT	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9
Existing Wind*	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Granger Landfill Gas	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total	59.5	59.5	59.5	59.5	59.5	59.5	59.5	59.5	59.5
Future Resources									
SCP Coal wCCS	-	-	-	-	-	-	-	-	-
Combined Cycle	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	-	-	-	-	-	-
Heritage Wind*	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
New Solar	-	-	-	-	-	-	-	-	-
TCLP Biomass	-	-	-	-	-	-	-	-	-
Market Purchases	30.6	31.6	32.2	32.8	32.8	34.0	34.7	35.3	35.4
Total	31.4	32.4	33.0	33.6	33.6	34.8	35.5	36.1	36.2
Total Capacity	91.0	92.0	92.5	93.1	93.1	94.3	95.0	95.7	95.7
Surplus/(Deficiency)	-	-	-	-	-	-	-	-	-
Energy from Renewable Resources	9.6%	9.5%	9.4%	9.3%	9.3%	9.2%	9.1%	9.0%	8.9%
State REP Requirement	9.6%	9.5%	9.5%	9.4%	9.3%	9.2%	9.1%	9.0%	8.9%
TCLP RPS Goal	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%

* Reflects a capacity credit for resource adequacy purposes of 8% of nameplate capacity per the currently proposed MISO default standard.

Table D1.2

Traverse City Light & Power

Resource Plan - Annual

Optimal Plan - Case 1

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Peak Demand (MW)										
Peak Demand	74.9	75.1	74.9	75.5	77.2	77.5	77.5	78.3	78.7	79.1
Reserves	11.2	11.3	11.2	11.3	11.6	11.6	11.6	11.7	11.8	11.9
Capacity Requirements	86.1	86.4	86.1	86.8	88.8	89.2	89.1	90.0	90.5	90.9
Capacity Resources (MW)										
Existing Resources										
Belle River	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Campbell 3	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Kalkaska CT	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9
Existing Wind*	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Granger Landfill Gas	0.3	0.8	0.9	1.4	1.4	1.7	1.7	1.7	1.7	1.7
Total	58.1	58.6	58.7	59.3	59.3	59.5	59.5	59.5	59.5	59.5
Future Resources										
SCP Coal wCCS	-	-	-	-	-	-	-	-	-	-
Combined Cycle	-	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	-	-	12.5	12.5	12.5	12.5	12.5
Heritage Wind*	-	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
New Solar	-	-	-	-	-	-	-	-	-	-
TCLP Biomass	-	-	-	-	-	10.0	10.0	10.0	10.0	10.0
Market Purchases	28.1	27.0	26.6	26.8	28.7	6.3	6.3	7.2	7.7	8.1
Total	28.1	27.8	27.4	27.6	29.5	29.7	29.6	30.5	31.0	31.4
Total Capacity	86.1	86.4	86.1	86.8	88.8	89.2	89.1	90.0	90.5	90.9
Surplus/(Deficiency)	-	-	-	-	-	-	-	-	-	-
Energy from Renewable Resources	0.9%	8.1%	8.5%	9.7%	9.4%	29.1%	28.8%	28.5%	28.0%	27.8%
State REP Requirement	0.0%	0.0%	2.0%	3.3%	5.0%	10.0%	9.9%	9.9%	9.8%	9.7%
TCLP RPS Goal	0.0%	0.0%	2.0%	3.3%	5.0%	10.0%	10.0%	10.0%	10.0%	10.0%

* Reflects a capacity credit for resource adequacy purposes of 8% of nameplate capacity per the currently proposed MISO default standard.

Table D1.2

Traverse City Light & Power

Resource Plan - Annual

Optimal Plan - Case 1

	2020	2021	2022	2023	2024	2025	2026	2027	2028
Peak Demand (MW)									
Peak Demand	79.1	80.0	80.5	81.0	81.0	82.0	82.6	83.2	83.2
Reserves	11.9	12.0	12.1	12.1	12.1	12.3	12.4	12.5	12.5
Capacity Requirements	91.0	92.0	92.5	93.1	93.1	94.3	95.0	95.7	95.7
Capacity Resources (MW)									
Existing Resources									
Belle River	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Campbell 3	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Kalkaska CT	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9
Existing Wind*	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Granger Landfill Gas	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total	59.5	59.5	59.5	59.5	59.5	59.5	59.5	59.5	59.5
Future Resources									
SCP Coal wCCS	-	-	-	-	-	-	-	-	-
Combined Cycle	-	-	-	-	-	-	-	-	-
Combustion Turbine	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Heritage Wind*	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
New Solar	-	-	-	-	-	-	-	-	-
TCLP Biomass	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Market Purchases	8.1	9.1	9.7	10.3	10.3	11.5	12.2	12.8	12.9
Total	31.4	32.4	33.0	33.6	33.6	34.8	35.5	36.1	36.2
Total Capacity	91.0	92.0	92.5	93.1	93.1	94.3	95.0	95.7	95.7
Surplus/(Deficiency)	-	-	-	-	-	-	-	-	-
Energy from Renewable Resources	27.0%	27.0%	26.6%	26.3%	26.3%	26.0%	25.8%	25.5%	25.4%
State REP Requirement	9.6%	9.5%	9.5%	9.4%	9.3%	9.2%	9.1%	9.0%	8.9%
TCLP RPS Goal	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%

* Reflects a capacity credit for resource adequacy purposes of 8% of nameplate capacity per the currently proposed MISO default standard.

Table D1.3

Traverse City Light & Power

Resource Plan - Annual

Optimal Plan - Case 2

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Peak Demand (MW)										
Peak Demand	74.9	75.1	74.9	75.5	77.2	77.5	77.5	78.3	78.7	79.1
Reserves	11.2	11.3	11.2	11.3	11.6	11.6	11.6	11.7	11.8	11.9
Capacity Requirements	86.1	86.4	86.1	86.8	88.8	89.2	89.1	90.0	90.5	90.9
Capacity Resources (MW)										
Existing Resources										
Belle River	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Campbell 3	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Kalkaska CT	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9
Existing Wind*	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Granger Landfill Gas	0.3	0.8	0.9	1.4	1.4	1.7	1.7	1.7	1.7	1.7
Total	58.1	58.6	58.7	59.3	59.3	59.5	59.5	59.5	59.5	59.5
Future Resources										
SCP Coal wCCS	-	-	-	-	-	-	-	-	-	-
Combined Cycle	-	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	-	-	6.3	6.3	6.3	6.3	6.3
Heritage Wind*	-	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
New Solar	-	-	-	-	-	-	-	-	-	-
TCLP Biomass	-	-	-	-	-	20.0	20.0	20.0	20.0	20.0
Market Purchases	28.1	27.0	26.6	26.8	28.7	2.6	2.6	3.4	3.9	4.3
Total	28.1	27.8	27.4	27.6	29.5	29.7	29.6	30.5	31.0	31.4
Total Capacity	86.1	86.4	86.1	86.8	88.8	89.2	89.1	90.0	90.5	90.9
Surplus/(Deficiency)	-	-	-	-	-	-	-	-	-	-
Energy from Renewable Resources	0.9%	8.1%	8.5%	9.7%	9.4%	48.2%	47.6%	47.1%	46.2%	45.9%
State REP Requirement	0.0%	0.0%	2.0%	3.3%	5.0%	10.0%	9.9%	9.9%	9.8%	9.7%
TCLP RPS Goal	0.0%	0.0%	2.0%	3.3%	5.0%	10.0%	10.0%	10.0%	10.0%	10.0%

* Reflects a capacity credit for resource adequacy purposes of 8% of nameplate capacity per the currently proposed MISO default standard.

Table D1.3

Traverse City Light & Power

Resource Plan - Annual

Optimal Plan - Case 2

	2020	2021	2022	2023	2024	2025	2026	2027	2028
Peak Demand (MW)									
Peak Demand	79.1	80.0	80.5	81.0	81.0	82.0	82.6	83.2	83.2
Reserves	11.9	12.0	12.1	12.1	12.1	12.3	12.4	12.5	12.5
Capacity Requirements	91.0	92.0	92.5	93.1	93.1	94.3	95.0	95.7	95.7
Capacity Resources (MW)									
Existing Resources									
Belle River	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Campbell 3	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Kalkaska CT	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9
Existing Wind*	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Granger Landfill Gas	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total	59.5	59.5	59.5	59.5	59.5	59.5	59.5	59.5	59.5
Future Resources									
SCP Coal wCCS	-	-	-	-	-	-	-	-	-
Combined Cycle	-	-	-	-	-	-	-	-	-
Combustion Turbine	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Heritage Wind*	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
New Solar	-	-	-	-	-	-	-	-	-
TCLP Biomass	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Market Purchases	4.4	5.4	6.0	6.5	6.6	7.7	8.4	9.1	9.2
Total	31.4	32.4	33.0	33.6	33.6	34.8	35.5	36.1	36.2
Total Capacity	91.0	92.0	92.5	93.1	93.1	94.3	95.0	95.7	95.7
Surplus/(Deficiency)	-	-	-	-	-	-	-	-	-
Energy from Renewable Resources	44.4%	44.6%	43.9%	43.3%	43.3%	42.9%	42.5%	42.1%	41.9%
State REP Requirement	9.6%	9.5%	9.5%	9.4%	9.3%	9.2%	9.1%	9.0%	8.9%
TCLP RPS Goal	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%

* Reflects a capacity credit for resource adequacy purposes of 8% of nameplate capacity per the currently proposed MISO default standard.

Table D1.4

Traverse City Light & Power

Resource Plan - Annual

Optimal Plan - Case 3

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Peak Demand (MW)										
Peak Demand	74.9	75.1	74.9	75.5	77.2	77.5	77.5	78.3	78.7	79.1
Reserves	11.2	11.3	11.2	11.3	11.6	11.6	11.6	11.7	11.8	11.9
Capacity Requirements	86.1	86.4	86.1	86.8	88.8	89.2	89.1	90.0	90.5	90.9
Capacity Resources (MW)										
Existing Resources										
Belle River	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Campbell 3	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Kalkaska CT	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9
Existing Wind*	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Granger Landfill Gas	0.3	0.8	0.9	1.4	1.4	1.7	1.7	1.7	1.7	1.7
Total	58.1	58.6	58.7	59.3	59.3	59.5	59.5	59.5	59.5	59.5
Future Resources										
SCP Coal wCCS	-	-	-	-	-	-	-	-	-	-
Combined Cycle	-	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	-	-	-	-	-	-	-
Heritage Wind*	-	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
New Solar	-	-	-	-	-	-	-	-	-	-
TCLP Biomass	-	-	-	-	-	20.0	30.0	30.0	30.0	30.0
Market Purchases	28.1	27.0	26.6	26.8	28.7	8.9	-	-	0.2	0.6
Total	28.1	27.8	27.4	27.6	29.5	29.7	30.8	30.8	31.0	31.4
Total Capacity	86.1	86.4	86.1	86.8	88.8	89.2	90.3	90.3	90.5	90.9
Surplus/(Deficiency)	-	-	-	-	-	-	1.2	0.3	-	-
Energy from Renewable Resources	0.9%	8.1%	8.5%	9.7%	9.4%	48.2%	66.4%	65.8%	64.4%	64.0%
State REP Requirement	0.0%	0.0%	2.0%	3.3%	5.0%	10.0%	9.9%	9.9%	9.8%	9.7%
TCLP RPS Goal	0.0%	0.0%	2.0%	3.3%	5.0%	10.0%	10.0%	10.0%	10.0%	10.0%

* Reflects a capacity credit for resource adequacy purposes of 8% of nameplate capacity per the currently proposed MISO default standard.

Table D1.4

Traverse City Light & Power

Resource Plan - Annual

Optimal Plan - Case 3

	2020	2021	2022	2023	2024	2025	2026	2027	2028
Peak Demand (MW)									
Peak Demand	79.1	80.0	80.5	81.0	81.0	82.0	82.6	83.2	83.2
Reserves	11.9	12.0	12.1	12.1	12.1	12.3	12.4	12.5	12.5
Capacity Requirements	91.0	92.0	92.5	93.1	93.1	94.3	95.0	95.7	95.7
Capacity Resources (MW)									
Existing Resources									
Belle River	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Campbell 3	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Kalkaska CT	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9
Existing Wind*	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Granger Landfill Gas	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total	59.5	59.5	59.5	59.5	59.5	59.5	59.5	59.5	59.5
Future Resources									
SCP Coal wCCS	-	-	-	-	-	-	-	-	-
Combined Cycle	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	-	-	-	-	-	-
Heritage Wind*	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
New Solar	-	-	-	-	-	-	-	-	-
TCLP Biomass	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Market Purchases	0.6	1.6	2.2	2.8	2.8	4.0	4.7	5.3	5.4
Total	31.4	32.4	33.0	33.6	33.6	34.8	35.5	36.1	36.2
Total Capacity	91.0	92.0	92.5	93.1	93.1	94.3	95.0	95.7	95.7
Surplus/(Deficiency)	-	-	-	-	-	-	-	-	-
Energy from Renewable Resources	61.9%	62.1%	61.1%	60.2%	60.3%	59.7%	59.3%	58.6%	58.4%
State REP Requirement	9.6%	9.5%	9.5%	9.4%	9.3%	9.2%	9.1%	9.0%	8.9%
TCLP RPS Goal	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%

* Reflects a capacity credit for resource adequacy purposes of 8% of nameplate capacity per the currently proposed MISO default standard.

Table D2.1

Traverse City Light & Power

Power Supply Costs of Resource Plan

Existing Resources

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Net Production Costs [1]	$ 19,182,895	$ 21,619,643	$ 26,754,582	$ 27,837,405	$ 29,138,525	$ 30,827,049	$ 31,345,197	$ 32,302,940	$ 33,866,377	$ 36,010,406	$ 36,996,695
Existing Debt Service Cost	$ 3,688,000	$ 3,692,000	$ 3,687,000	$ 3,672,000	$ 3,629,000	$ 3,590,000	$ 2,872,000	$ 2,872,000	$ 2,153,000	$ 1,817,000	$ 1,817,000
Other Debt Service Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Service Cost of New Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Costs	$ 22,870,895	$ 25,311,643	$ 30,441,582	$ 31,509,405	$ 32,767,525	$ 34,417,049	$ 34,217,197	$ 35,174,940	$ 36,019,377	$ 37,827,406	$ 38,813,695
Energy (MWh)	349,844	351,857	353,027	355,531	364,545	366,828	369,963	371,787	375,291	378,214	381,071
Total Power Costs ($/MWh)	$ 65.37	$ 71.94	$ 86.23	$ 88.63	$ 89.89	$ 93.82	$ 92.49	$ 94.61	$ 95.98	$ 100.02	$ 101.85
Levelized Power Costs ($/MWh)	$ 102.87										
Standard Deviation ($/MWh)	$ 12.60										
5th Percentile ($/MWh)	$ 57.22	$ 63.16	$ 76.01	$ 75.76	$ 76.83	$ 75.11	$ 74.08	$ 77.19	$ 74.44	$ 79.26	$ 80.34
95th Percentile ($/MWh)	$ 72.93	$ 80.97	$ 99.43	$ 101.94	$ 105.11	$ 111.88	$ 109.29	$ 111.83	$ 115.36	$ 125.46	$ 126.52

Table D2.2

Traverse City Light & Power

Power Supply Costs of Resource Plan

Optimal Plan - Case 1

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Net Production Costs [1]	$ 19,182,895	$ 21,619,643	$ 26,754,582	$ 27,837,405	$ 29,138,525	$ 24,815,462	$ 25,595,329	$ 26,679,539	$ 28,300,587	$ 30,143,512	$ 31,370,559
Existing Debt Service Cost	$ 3,688,000	$ 3,692,000	$ 3,687,000	$ 3,672,000	$ 3,629,000	$ 3,590,000	$ 2,872,000	$ 2,872,000	$ 2,153,000	$ 1,817,000	$ 1,817,000
Other Debt Service Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Service Cost of New Resources	$ -	$ -	$ -	$ -	$ -	$ 4,704,155	$ 4,704,155	$ 4,704,155	$ 4,704,155	$ 4,704,155	$ 4,704,155
Transmission Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Costs	$ 22,870,895	$ 25,311,643	$ 30,441,582	$ 31,509,405	$ 32,767,525	$ 33,109,617	$ 33,171,484	$ 34,255,694	$ 35,157,742	$ 36,664,667	$ 37,891,714
Energy (MWh)	349,844	351,857	353,027	355,531	364,545	366,828	369,963	371,787	375,291	378,214	381,071
Total Power Costs ($/MWh)	$ 65.37	$ 71.94	$ 86.23	$ 88.63	$ 89.89	$ 90.26	$ 89.66	$ 92.14	$ 93.68	$ 96.94	$ 99.43
Levelized Power Costs ($/MWh)	$ 99.97										
Standard Deviation ($/MWh)	$ 10.93										
5th Percentile ($/MWh)	$ 57.22	$ 63.16	$ 76.01	$ 75.76	$ 76.83	$ 76.35	$ 76.40	$ 76.85	$ 76.86	$ 78.21	$ 82.12
95th Percentile ($/MWh)	$ 72.93	$ 80.97	$ 99.43	$ 101.94	$ 105.11	$ 105.79	$ 104.51	$ 106.28	$ 110.79	$ 116.32	$ 119.38

[1] Includes fuel costs, fixed and variable operation and maintenance costs, and environmental costs of all resources.

Table D2.1

Traverse City Light & Power

Power Supply Costs of Resource Plan

Existing Resources

	2021	2022	2023	2024	2025	2026	2027	2028
Net Production Costs [1]	$ 39,765,432	$ 41,855,137	$ 44,263,147	$ 46,377,301	$ 49,685,459	$ 52,045,017	$ 53,484,397	$ 56,093,768
Existing Debt Service Cost	$ 1,817,000	$ 1,816,000	$ 1,813,000	$ 1,812,000	$ 1,812,000	$ 1,812,000	$ -	$ -
Other Debt Service Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Service Cost of New Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Costs	$ 41,582,432	$ 43,671,137	$ 46,076,147	$ 48,189,301	$ 51,497,459	$ 53,857,017	$ 53,484,397	$ 56,093,768
Energy (MWh)	384,471	388,492	391,617	395,230	399,400	402,603	406,429	411,347
Total Power Costs ($/MWh)	$ 108.15	$ 112.41	$ 117.66	$ 121.93	$ 128.94	$ 133.77	$ 131.60	$ 136.37
Levelized Power Costs ($/MWh)								
Standard Deviation ($/MWh)								
5th Percentile ($/MWh)	$ 83.23	$ 80.23	$ 83.48	$ 89.74	$ 91.58	$ 93.56	$ 96.58	$ 101.01
95th Percentile ($/MWh)	$ 134.70	$ 137.61	$ 145.57	$ 153.13	$ 161.59	$ 167.51	$ 168.72	$ 173.01

Table D2.2

Traverse City Light & Power

Power Supply Costs of Resource Plan

Optimal Plan - Case 1

	2021	2022	2023	2024	2025	2026	2027	2028
Net Production Costs [1]	$ 33,544,306	$ 35,634,829	$ 37,780,650	$ 39,903,481	$ 42,635,022	$ 44,835,127	$ 46,216,660	$ 48,560,188
Existing Debt Service Cost	$ 1,817,000	$ 1,816,000	$ 1,813,000	$ 1,812,000	$ 1,812,000	$ 1,812,000	$ -	$ -
Other Debt Service Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Service Cost of New Resources	$ 4,704,155	$ 4,704,155	$ 4,704,155	$ 4,704,155	$ 4,704,155	$ 4,704,155	$ 4,704,155	$ 4,704,155
Transmission Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Costs	$ 40,065,461	$ 42,154,984	$ 44,297,805	$ 46,419,636	$ 49,151,177	$ 51,351,282	$ 50,920,815	$ 53,264,343
Energy (MWh)	384,471	388,492	391,617	395,230	399,400	402,603	406,429	411,347
Total Power Costs ($/MWh)	$ 104.21	$ 108.51	$ 113.12	$ 117.45	$ 123.06	$ 127.55	$ 125.29	$ 129.49
Levelized Power Costs ($/MWh)								
Standard Deviation ($/MWh)								
5th Percentile ($/MWh)	$ 84.05	$ 82.25	$ 82.91	$ 87.93	$ 92.89	$ 93.14	$ 93.79	$ 98.76
95th Percentile ($/MWh)	$ 124.44	$ 127.24	$ 136.24	$ 140.81	$ 150.56	$ 156.58	$ 156.44	$ 160.54

[1] Includes fuel costs, fixed and variable operation and maintenance costs, and environmental costs of all resources.

Table D2.3

Traverse City Light & Power

Power Supply Costs of Resource Plan

Optimal Plan - Case 2

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Net Production Costs [1]	$ 19,182,895	$ 21,619,643	$ 26,754,582	$ 27,837,405	$ 29,138,525	$ 22,969,565	$ 23,729,549	$ 24,787,493	$ 26,276,628	$ 27,896,810	$ 29,119,155
Existing Debt Service Cost	$ 3,688,000	$ 3,692,000	$ 3,687,000	$ 3,672,000	$ 3,629,000	$ 3,590,000	$ 2,872,000	$ 2,872,000	$ 2,153,000	$ 1,817,000	$ 1,817,000
Other Debt Service Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Service Cost of New Resources	$ -	$ -	$ -	$ -	$ -	$ 7,377,587	$ 7,377,587	$ 7,377,587	$ 7,377,587	$ 7,377,587	$ 7,377,587
Transmission Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Costs	$ 22,870,895	$ 25,311,643	$ 30,441,582	$ 31,509,405	$ 32,767,525	$ 33,937,152	$ 33,979,136	$ 35,037,080	$ 35,807,215	$ 37,091,397	$ 38,313,742
Energy (MWh)	349,844	351,857	353,027	355,531	364,545	366,828	369,963	371,787	375,291	378,214	381,071
Total Power Costs ($/MWh)	$ 65.37	$ 71.94	$ 86.23	$ 88.63	$ 89.89	$ 92.52	$ 91.84	$ 94.24	$ 95.41	$ 98.07	$ 100.54
Levelized Power Costs ($/MWh)	$ 100.02										
Standard Deviation ($/MWh)	$ 9.20										
5th Percentile ($/MWh)	$ 57.22	$ 63.16	$ 76.01	$ 75.76	$ 76.83	$ 82.58	$ 81.48	$ 81.92	$ 82.79	$ 83.77	$ 85.39
95th Percentile ($/MWh)	$ 72.93	$ 80.97	$ 99.43	$ 101.94	$ 105.11	$ 105.76	$ 105.78	$ 109.09	$ 110.97	$ 115.18	$ 116.44

Table D2.4

Traverse City Light & Power

Power Supply Costs of Resource Plan

Optimal Plan - Case 3

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Net Production Costs [1]	$ 19,182,895	$ 21,619,643	$ 26,754,582	$ 27,837,405	$ 29,138,525	$ 24,179,305	$ 21,970,400	$ 22,992,817	$ 24,371,715	$ 25,737,596	$ 26,933,512
Existing Debt Service Cost	$ 3,688,000	$ 3,692,000	$ 3,687,000	$ 3,672,000	$ 3,629,000	$ 3,590,000	$ 2,872,000	$ 2,872,000	$ 2,153,000	$ 1,817,000	$ 1,817,000
Other Debt Service Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Service Cost of New Resources	$ -	$ -	$ -	$ -	$ -	$ 6,700,680	$ 10,131,427	$ 10,131,427	$ 10,131,427	$ 10,131,427	$ 10,131,427
Transmission Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Costs	$ 22,870,895	$ 25,311,643	$ 30,441,582	$ 31,509,405	$ 32,767,525	$ 34,469,985	$ 34,973,827	$ 35,996,244	$ 36,656,142	$ 37,686,023	$ 38,881,939
Energy (MWh)	349,844	351,857	353,027	355,531	364,545	366,828	369,963	371,787	375,291	378,214	381,071
Total Power Costs ($/MWh)	$ 65.37	$ 71.94	$ 86.23	$ 88.63	$ 89.89	$ 93.97	$ 94.53	$ 96.82	$ 97.67	$ 99.64	$ 102.03
Levelized Power Costs ($/MWh)	$ 100.38										
Standard Deviation ($/MWh)	$ 8.02										
5th Percentile ($/MWh)	$ 57.22	$ 63.16	$ 76.01	$ 75.76	$ 76.83	$ 83.63	$ 84.95	$ 86.98	$ 87.22	$ 87.32	$ 89.48
95th Percentile ($/MWh)	$ 72.93	$ 80.97	$ 99.43	$ 101.94	$ 105.11	$ 107.78	$ 106.64	$ 108.39	$ 109.78	$ 113.47	$ 116.19

[1] Includes fuel costs, fixed and variable operation and maintenance costs, and environmental costs of all resources.

Table D2.3

Traverse City Light & Power

Power Supply Costs of Resource Plan

Optimal Plan - Case 2

	2021	2022	2023	2024	2025	2026	2027	2028
Net Production Costs [1]	$ 31,105,011	$ 33,026,887	$ 34,976,465	$ 37,011,643	$ 39,432,573	$ 41,480,548	$ 42,848,328	$ 45,008,935
Existing Debt Service Cost	$ 1,817,000	$ 1,816,000	$ 1,813,000	$ 1,812,000	$ 1,812,000	$ 1,812,000	$ -	$ -
Other Debt Service Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Service Cost of New Resources	$ 7,377,587	$ 7,377,587	$ 7,377,587	$ 7,377,587	$ 7,377,587	$ 7,377,587	$ 7,377,587	$ 7,377,587
Transmission Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Costs	$ 40,299,598	$ 42,220,474	$ 44,167,052	$ 46,201,230	$ 48,622,160	$ 50,670,135	$ 50,225,915	$ 52,386,522
Energy (MWh)	384,471	388,492	391,617	395,230	399,400	402,603	406,429	411,347
Total Power Costs ($/MWh)	$ 104.82	$ 108.68	$ 112.78	$ 116.90	$ 121.74	$ 125.86	$ 123.58	$ 127.35
Levelized Power Costs ($/MWh)								
Standard Deviation ($/MWh)								
5th Percentile ($/MWh)	$ 87.42	$ 88.38	$ 88.49	$ 93.25	$ 99.00	$ 99.19	$ 96.96	$ 99.32
95th Percentile ($/MWh)	$ 121.64	$ 123.94	$ 131.25	$ 135.97	$ 143.08	$ 150.42	$ 148.73	$ 154.14

Table D2.4

Traverse City Light & Power

Power Supply Costs of Resource Plan

Optimal Plan - Case 3

	2021	2022	2023	2024	2025	2026	2027	2028
Net Production Costs [1]	$ 28,717,483	$ 30,495,983	$ 32,241,192	$ 34,172,720	$ 36,294,260	$ 38,177,621	$ 39,526,285	$ 41,525,232
Existing Debt Service Cost	$ 1,817,000	$ 1,816,000	$ 1,813,000	$ 1,812,000	$ 1,812,000	$ 1,812,000	$ -	$ -
Other Debt Service Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Service Cost of New Resources	$ 10,131,427	$ 10,131,427	$ 10,131,427	$ 10,131,427	$ 10,131,427	$ 10,131,427	$ 10,131,427	$ 10,131,427
Transmission Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Power Costs	$ 40,665,910	$ 42,443,410	$ 44,185,619	$ 46,116,147	$ 48,237,687	$ 50,121,048	$ 49,657,712	$ 51,656,659
Energy (MWh)	384,471	388,492	391,617	395,230	399,400	402,603	406,429	411,347
Total Power Costs ($/MWh)	$ 105.77	$ 109.25	$ 112.83	$ 116.68	$ 120.78	$ 124.49	$ 122.18	$ 125.58
Levelized Power Costs ($/MWh)								
Standard Deviation ($/MWh)								
5th Percentile ($/MWh)	$ 90.51	$ 93.82	$ 90.79	$ 95.26	$ 95.43	$ 97.74	$ 97.06	$ 97.39
95th Percentile ($/MWh)	$ 121.25	$ 124.53	$ 129.49	$ 134.86	$ 138.08	$ 144.13	$ 142.57	$ 149.66

[1] Includes fuel costs, fixed and variable operation and maintenance costs, and environmental costs of all resources.

Appendix E
LIST OF ACRONYMS

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Appendix E
LIST OF ACRONYMS

ACEC	Advanced Cleaner Energy Credits
ACES	American Clean Energy and Security
AGR	Agricultural Residues
AMW	Average MW
BCEI	Blue Chip Economic Indicators
CCS	Carbon Capture and Sequestration
CE	Consumers Energy
CF	Capacity Factor
CHP	Combined Heat and Power
City	City of Traverse City
CPI	Consumer Price Index
CT	Combustion Turbine
DOE	Department of Energy
DTE	Detroit Edison
EOP	Energy Optimization Plan
FOM	Fixed Operation and Maintenance
FPL	Forest Products Laboratory
FR	Forest Residues
GHG	Greenhouse gas
GWh	Gigawatt-hour
IGCC	Integrated gasification combined cycle
IRP	Integrated resource plan

kW	Kilowatt
kWh	Kilowatt-hour
lb	Pound
MISO	Mid-West Independent System Operator
MMBtu	Million Btu
MPPA	Michigan Public Power Agency
MUW	Mill and Urban Waste
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratories
O&M	Operation and Maintenance
ORNL	Oakridge National Laboratories
PPA	Purchase Power Agreement
PV	Photovoltaic
REC	Renewable Energy Credits
REP	Renewable Energy Plan (specific to Michigan)
RPS	Renewable Portfolio Standard
SCP Coal	Supercritical Pulverized Coal-fired Steam Plant
SERF	Stochastic Econometric Regional Forecasting
SWG	Switch Grass
TCLP	Traverse City Light and Power
VOM	Variable Operation and Maintenance
WDS	Wood-waste solids