A REGULAR MEETING

Of The

TRAVERSE CITY LIGHT AND POWER BOARD

Will Be Held On

TUESDAY, September 24, 2013

At

5:15 p.m.

In The

COMMISSION CHAMBERS
(2nd floor, Governmental Center)
400 Boardman Avenue

Traverse City Light and Power will provide necessary reasonable auxiliary aids and services, such as signers for the hearing impaired and audio tapes of printed materials being considered at the meeting, to individuals with disabilities at the meeting/hearing upon notice to Traverse City Light and Power. Individuals with disabilities requiring auxiliary aids or services should contact the Light and Power Department by writing or calling the following.

Stephanie Tvardek
Administrative Assistant
1131 Hastings Street
Traverse City, MI 49686
(231) 932-4543

Traverse City Light and Power
1131 Hastings Street
Traverse City, MI 49686
(231) 922-4940

Posting Date: 09-19-13
4:00 p.m.

AGENDA

Pledge of Allegiance

1. Roll Call

2. Consent Calendar

The purpose of the consent calendar is to expedite business by grouping non-controversial items together to be dealt with by one Board motion without discussion. Any member of the Board, staff or the public may ask that any item on the consent calendar be removed therefrom and placed elsewhere on the agenda for full discussion. Such requests will be automatically respected. If an item is not removed from the consent calendar, the action noted in parentheses on the agenda is approved by a single Board action adopting the consent calendar.

None.

Items Removed from the Consent Calendar

None.

3. Unfinished Business

None.

4. New Business

a. Consideration of approving minutes of the Regular Meeting of September 10, 2013. (p. 3)

b. Consideration of authorizing a Tree Trimming Services Agreement with Penn Line. (Arends/Watson) (p. 6)

5. Appointments

None.

6. Reports and Communications

a. From Legal Counsel.

b. From Staff.

1. Lansing Board of Water & Light Contract Power Purchase – 2014. (Arends/Bob Dyer) (p. 9)
2. Report on outage feedback survey. (Wheaton) (p. 34)

c. From Board.

7. Public Comment

/st

TRAVERSE CITY
LIGHT AND POWER BOARD

Minutes of Regular Meeting
Held at 5:15 p.m., Commission Chambers, Governmental Center
Tuesday, September 10, 2013

Board Members -

Present: Barbara Budros, Jim Carruthers, Jan Geht, Jeff Palisin, Bob Spence, John Taylor, Patrick McGuire

Ex Officio Member -

Present: Jered Ottenwess, City Manager

Others: Tim Arends, W. Peter Doren, Scott Menhart, Karla Myers-Beman, Tom Olney, Stephanie Tvardek, Jessica Wheaton

The meeting was called to order at 5:15 p.m. by Chairman McGuire.

<u>Item 2 on the Agenda being Consent Calendar</u>

Moved by Carruthers, seconded by Budros, that the following actions, as recommended on the Consent Calendar portion of the Agenda, be approved:

a. Minutes of the Regular Board Meeting of August 27, 2013.

b. Appointment of Karla Myers-Beman as Official Delegate to cast official votes on behalf of TCL&P at the Annual Meeting of the Municipal Employees Retirement Systems.

Budros noted item 2b was to approve Karla Myers-Beman as Official Delegate *and Kelli Schroeder as Alternate Delegate.*

CARRIED unanimously.

<u>Items removed from the Consent Calendar</u>

None.

<u>Item 3 on the Agenda being Old Business</u>

None.

<u>Item 4 on the Agenda being New Business</u>

4(a). Consideration of authorizing a Resolution to Amend City Ordinance – Lien & Tampering as civil infraction.

The following individuals addressed the Board:

Tim Arends, Executive Director
Jered Ottenwess, City Manager
Karla Myers-Beman, Controller

Moved by Carruthers, seconded by Palisin, that the Light and Power Board adopts the Resolution to Request the City Commission Amend Section 1046 of the Traverse City Code of Ordinances.

CARRIED unanimously.

4(b). Consideration of removing the PCR cap.

The following individuals addressed the Board:

Tim Arends, Executive Director
Karla Myers-Beman, Controller

Moved by Palisin, seconded by Spence, that the Light and Power Board approves lifting the PCR cap for residential and commercial customers effective October 1, 2013.

The following individuals from the public addressed the Board:

Rick Buckhalter, 932 Kelley Street, Ratepayer

CARRIED unanimously.

<u>Item 5 on the Agenda being Appointments</u>

None.

<u>Item 6 on the Agenda being Reports and Communications</u>

A. From Legal Counsel.

None.

B. From Staff.

1. Tim Arends and Rob Bacigalupi, Interim Executive Director of DDA, spoke re: TCL&P providing Wi-Fi in the DDA District.

   The following individuals addressed the Board:

   Scott Menhart, Manager of Telecom and Technology
   W. Peter Doren, General Counsel

Chairman McGuire announced the board would hear general public comment at this time, before moving on to agenda item 6(B)2.

Public Comment:

Mayor Michael Estes, Ratepayer
Rick Buckhalter, 932 Kelley Street, Ratepayer

6:43 p.m. Chairman McGuire called the Board at ease.
6:45 p.m. Chairman McGuire called the meeting to order.

2. Tim Arends and Steve VanderMeer, Hometown Connections (via conference call), spoke re: strategic planning focus groups and survey.

   The following individuals addressed the Board:

   Jessica Wheaton, Marketing & Community Relations Coordinator

3. Jessica Wheaton spoke re: the Historic Barns Geothermal Heating & Cooling System.

C. From Board.

1. Barbara Budros spoke re: opinions drafted by the City Attorney regarding the coal dock.

Item 7 on the Agenda being Public Comment

No one from the public commented.

There being no objection, Chairman McGuire declared the meeting adjourned at 7:25 p.m.

Tim Arends, Secretary
LIGHT AND POWER BOARD

/st

EST. 1912 TRAVERSE CITY LIGHT & POWER 100 YEARS

To: **Light & Power Board**
From: Tim Arends, Executive Director
Date: September 16, 2013
Subject: Tree Trimming Services Agreement

On April 23, 2013 the Board approved a three year contract with Trees, Inc. for line clearance and other tree trimming services for TCL&P. As you know, one of their employees died from direct contact with the primary distribution line on August 7, 2013.

Due to the nature of the incident I suspended Trees, Inc. while TCL&P and others conducted investigations into the cause of the incident. TCL&P's investigation determined that the employee violated safe distance requirements from the primary voltage line, and used climbing spikes on the tree that he was in when he died. Both of these violations are a violation of the Agreement between Trees, Inc. and TCL&P and are deemed "material" breaches of contract, as stated in the Agreement.

As follow-up to this finding in the investigation, I had employees view other trees that were recently trimmed by Trees, Inc. and they provided me with photographic evidence of several trees that climbing spikes were used. The company was on notice that climbing spikes were not permitted without prior written consent of TCL&P; in addition, that part of the Agreement was reinforced in person on day one with the crew that was working on TCL&P's system.

For the above reason, and because Trees, Inc. did not adequately provide for the safety of its employees, I have terminated the Agreement between TCL&P and Trees, Inc. in a letter dated September 17, 2013 addressed to the company's attorney.

Attached is a memorandum from Blake Wilson indicating that Penn Line Services, Inc. has agreed to honor its original bid which was $1,830.40 more than Trees, Inc. The utility needs these services to recommence, and Penn Line Services was the most recent company performing these services for TCL&P and performed well for the utility for the past two years.

Staff recommends selecting Penn Line Service, Inc. as they are the next low bidder for the defined work scope. If the Board is in agreement the following motion would be appropriate:

(RECOMMENDED MOTION ON NEXT PAGE)

FOR THE LIGHT & POWER BOARD MEETING OF SEPTEMBER 24, 2013

MOVED BY ______________________, SECONDED BY________________________,
THAT THE BOARD AUTHORIZE THE CHAIRMAN AND THE SECRETARY TO ENTER INTO A THREE YEAR TREE TRIMMING SERVICES AGREEMENT WITH PENN LINE SERVICES INC. IN THE AMOUNT OF $442,457.60; SUBJECT TO APPROVAL AS TO SUBSTANCE BY THE EXECUTIVE DIRECTOR AND AS TO FORM BY GENERAL COUNSEL.

TRAVERSE CITY
LIGHT & POWER

To:	**Tim Arends, Executive Director**
From:	Blake Wilson, System Engineer
Date:	September 16, 2013
Subject:	Tree Trimming Services Agreement

I spoke with Dennis Nelson on 9-10-13 and he agreed to honor the original bid that Penn Line Services Inc. submitted to Traverse City Light and Power for the three year contract period.

Bids have been obtained for tree trimming services on Traverse City Light & Power's (TCL&P) utility system for 2013-2017 (3 years). Bid pricing was at an hourly rate for a two person crew with truck, chipper and other related equipment for the purpose of line clearance tree trimming. TCL&P's electric distribution, transmission and fiber system are to be trimmed under this contract. Requests were sent out to seven companies and bids were received as follows:

		Time and Material Costs		
Bidder	**3 Year Total**	**Year 1**	**Year 2**	**Year 3**
Trees Inc.	$440,627.20	(CONTRACT TERMINATED)		
Penn Line Services Inc	$442,457.60	$70.13	$70.77	$71.82
Townsend	$464,713.60	$73.25	$74.36	$75.81
Asplundh Tree Expert Co.	$479,211.20	$75.95	$76.79	$77.65
The Energy Group	$562,473.60	$87.49	$90.11	$92.82
Nelson Tree Service	NO BID	N/A	N/A	N/A
NG Gilbert	NO BID	N/A	N/A	N/A

EST. 1912 100 YEARS

TRAVERSE CITY
LIGHT & POWER

To: **Light & Power Board**
From: Tim Arends, Executive Director
Date: September 19, 2013
Subject: Lansing Contract Power Purchase - 2014

In accordance with the contract between Traverse City Light & Power ("TCL&P") and Lansing Board of Water & Light ("LBW&L"), TCL&P is required to reserve monthly blocks of energy from LBW&L by October 1st of each year for the next calendar year (this year LBW&L has extended that deadline to November 1st). TCL&P entered into this power purchase agreement with LBW&L to provide power from 2011 through 2015 (often referred to as a "bridge" contract) due to the Michigan Public Power Agency power pool being dissolved at the end of 2010.

The decision on what quantity of power to purchase from LBW&L for base block energy and peaking block energy is an important one that requires expertise in power supply and power markets. The decision has a significant financial impact on the utility. For these reasons, I have contracted with Mr. Bob Dyer of RTD Consulting, LLC (he was the generation/power purchase expert for the Hometown Efficiency Study) to analyze TCL&P's system requirement for 2014. Mr. Dyer will be in attendance at your meeting to educate the board and the public on the requirements of the LBW&L contract, discussion of TCL&P's system requirements, and to explain his recommendation to staff for 2014 purchases from LBW&L.

In addition to this presentation, I will be requesting of the Board to provide input to staff on information it will need in order to make informed decisions on providing staff direction in addressing long-term energy supply for the utility. The LBW&L contract is set to expire at the end of 2015; TCL&P must notify LBW&L one year in advance, or by December 31, 2014, if it intends to extend the Agreement or not. Part of that decision making process may involve a decision from the Board regarding local generation – to pursue it or be a power purchaser? If a power purchaser, what type of contracts to purchase? Long-term, short-term, small or large quantities, renewable energy – how much?

This meeting will essentially be the kickoff meeting to the larger power supply decisions that will need to be made over the next 18 months. I will be prepared to outline for the Board a plan on educating, analyzing, and coming to decision points that will include a timeline for making some of these critical decisions for the utility.

This agenda item is expected to be a lengthy discussion that I estimate will run from 45 minutes to 1 hour.

RTD CONSULTING, LLC

September 12, 2013

Timothy J. Arends
Traverse City Light & Power
Executive Director
1131 Hastings St.
Traverse City MI 49686

Re: Power Supply recommendation for 2014

Dear Tim,

We have completed our analysis of the requirements for the TCLP system for 2014. In the course of this analysis we have looked at a number of scenarios that have been used to "bound the problem". Attached is a detailed report that goes through the assumption, modeling techniques and scenarios investigated. The goal was to provide you with recommendations to the following questions:

- **Does Traverse City have sufficient capacity to support their capacity obligations?**
    - See the table below for the estimated capacity purchases required to meet TCLPs obligations monthly for 2014:

Month	Available Capacity (Mw)[1]	Month	Available Capacity(Mw)[1]
Jan 2014	0.0	Jul 2014	-9.2
Feb 2014	0.3	Aug 2014	-11.5
Mar 2014	1.2	Sep 2014	-8.0
Apr 2014	3.6	Oct 2014	-.3
May 2014	1.8	Nov 2014	3.7
Jun 2014	-12.6	Dec 2014	1.4

Note 1: a negative quantity indicates a shortage of capacity.

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- **What is the risk of riding on the MISO spot market?**
    - There is some risk to market price for energy form MISO. The prices in the MISO market would have to increase significantly before its average would exceed the prices available from LWBL in their existing contract. In addition, the Kalkaska CT remains a good hedge against large market prices increases. The principal driver for cost in MISO is natural gas prices and while it is only a forecast, there does not appear to be any significant short term forces that would cause significant price increases in the foreseeable future (through 2014).

- **What are the appropriate contract volumes strikes for the Lansing Base Block, Peaking Block and Peaking Option Block contracts?**
    - TCLP should continue to take the minimum required under the LBWL contract. This should result in TCLP maximizing its cash flow with the Risk Exposure being decreased over other available options.

- **What options are available to displace additional contract volumes and/or MISO spot transactions?**
    - There were other options investigated. Financial Forward contracts and Out of the Money call options were evaluated. While they produced results more favorable than increasing the LBWL contract, they are not recommended.

- **How do different contract choices affect the cash flow and risk profile of the portfolio?**
    - Due to the nature of the TCLP portfolio there is limited risk and limited options to improve cash flow. The limited risk is a direct result of the Kalkaska CT. All of the choices available to TCLP do not significantly improve the risk and in some cases, actual increase risks while decreasing cash flow. Therefore, no additional contracts are recommended.

The attached report is provided to you and is the support for the recommendations made above. After you have reviewed the report, please feel free to contract me with any comments or questions. Also, I will be in your office on September 24, at 10:00AM to meet with you and later that day with your Board to discuss this report.

Sincerely,

R. T. Dyer

R. T. Dyer

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2014 Power Supply Assessment
For
Traverse City Light and Power

TCLP Management Review

Prepared by

Robert Dyer
Mike Jones
September 12, 2013

Assessment Overview

A one year, hourly economic dispatch model has been used to evaluate Traverse City Power and Light's (TCLP) expected power supply position and to assess the potential risk to that position, if actual market conditions vary significantly from the forecast values. Additionally, the capacity needs of TCLP were assessed with a basic capacity balance of contracted resources compared to the forecast load and reserve requirements.

The purpose of the TCLP Portfolio Assessment is to establish the optimal portfolio for the upcoming calendar year, in order to support the appropriate notifications to Lansing for the Block Purchase Agreements and to investigate other market products that could be used to offset either additional Lansing purchases above minimums or MISO market exposure. Specific questions to be answered include:

- Does TCLP have sufficient capacity to support their capacity obligations?
- What is the risk of riding on the MISO spot market?
- What are the appropriate contract volumes strikes for the Lansing Base Block, Peaking Block and Peaking Option Block contracts?
- What options are available to displace additional contract volumes and/or MISO spot transactions?
- How do different contract choices affect the cash flow and risk profile of the portfolio?

General Observations

The current TCLP Portfolio is a highly constrained portfolio with few dispatchable resources. This results in a portfolio with little downside risk, since the current contract positions have been locked in and are sufficient to meet the vast majority of TCLP's needs. The variability that should be expected is the upside benefit when markets become favorable for dispatching resources like the Kalkaska CT.

As the current contract with Lansing concludes in coming years, Traverse City will experience an opportunity to lower its production costs, but with that opportunity could also come substantially increased risk. RTO style markets reward participants who bring operating flexibility and wide dispatch ranges to the market. They tend to penalize must take units (wind), units with long minimum run times and long start times.

RTO style markets disaggregate capacity and energy transactions, such that, when a generator sells capacity to counterparty in the MISO market, the operator of the generator incurs an obligation to offer that unit into the market, not to deliver energy from it to the purchasing entity. As a result, a utility has the option to purchase capacity only and then simply take energy from the spot market (or more appropriately, purchase their energy from a separate entity). MISO will decide whether it wants the capacity unit online or not and will pay the generator appropriately. This results in a fairly robust financial energy market with an underlying bilateral capacity market and allows for capacity auctions where the buyer and seller are unconcerned as to who is purchasing the capacity.

Major Modeling Assumptions

The model assumes operation of current generation will not differ significantly from historic performance and that the performance of the City's wind resources will not affect its decision on how to dispatch resources into the market. Due to the desire to contain costs and the fact that wind resources are independent of dispatch decisions, a wind model was not developed and the wind resources were considered to be outside the scope of this study, with the exception of their contribution to the City's capacity needs.

An estimate of the impact of the Heritage Wind Project on the TCLP net cash flow, assuming that the cost of Heritage is $109.24 (from June 2013 Energy Purchase Invoice) and most of the power is generated and sold during off-peak hours is shown in Table 1 below.

Table 1 – Estimate of Wind Net Revenue by Capacity Factor

	Capacity Factor			
Month	**5%**	**10%**	**20%**	**30%**
Jan-14	$(28,918)	$(57,835)	$(115,670)	$(173,506)
Feb-14	$(25,680)	$(51,360)	$(102,719)	$(154,079)
Mar-14	$(29,155)	$(58,310)	$(116,621)	$(174,931)
Apr-14	$(27,164)	$(54,327)	$(108,655)	$(162,982)
May-14	$(29,701)	$(59,402)	$(118,805)	$(178,207)
Jun-14	$(28,224)	$(56,448)	$(112,896)	$(169,344)
Jul-14	$(27,988)	$(55,977)	$(111,953)	$(167,930)
Aug-14	$(27,841)	$(55,683)	$(111,366)	$(167,049)
Sep-14	$(28,384)	$(56,768)	$(113,537)	$(170,305)
Oct-14	$(29,543)	$(59,086)	$(118,172)	$(177,258)
Nov-14	$(27,897)	$(55,793)	$(111,586)	$(167,380)
Dec-14	$(28,973)	$(57,946)	$(115,893)	$(173,839)
Annual	**$(339,468)**	**$(678,936)**	**$(1,357,873)**	**$(2,036,809)**

Other assumptions include:

- Assets that were considered in establishing the TCLP's current net cash flow and risk profile include: TCLP's portions of Belle River 1 & 2, Campbell 3, Kalkaska CT, Granger Landfill Gas, the City's Native Load obligations and the minimum take quantities from the Lansing Base Block, Peaking Block and Peaking Option Block agreements.
- Due to the limited scope of the study and the random nature of forced outages, thus making them unfavorable for hedging, a forced outage model was not developed for this study. The financial risk of a forced outage is an outstanding risk outside of these results.

- Assets that were considered to meet additional needs include taking more than the minimum quantities from the Lansing Base Block, Peaking Block and Peaking Option Block agreements and purchasing financial forward and monthly call option products from the market.
- Based on historical patterns, all generation except Kalkaska was dispatched around the clock, with Kalkaska being economically dispatched into the market.
- The monthly call options were economically struck with perfect foresight of the spot market price.

Risk Model

The risk model used for this assessment is a deterministic, hourly, one year dispatch model using pre-determined risk scenarios to evaluate incremental changes in cash flow between scenarios with cash flow at risk being defined as the difference between the scenario being evaluated and the base scenario set at the expected system conditions. Some important definitions in this model include:

Deterministic – Discrete input values (as opposed to a stochastic distribution) are applied to a production costing model to determine a single point solution for each scenario.

Benefits

- Easily understood scenarios – deterministic models provide a solution for a specific set of conditions that are easily identified and understood (i.e. what happens to cash flow with an increase in gas price of 10%).
- More easily modeled than stochastic solutions – deterministic solutions for small systems are capable of being modeled in spreadsheets or other small scale solutions, rather than a commercial production costing model, thus reducing study cost.
- It is easier to trace causality for a specific outcome through the underlying model, which make the results more easily explainable.
- Required much smaller historic data sets (5 to 10 times smaller) to parameterize the input model.

Limitations

- Provides a limited solution set – if a specific set of conditions was not specifically selected as a scenario, the results of those conditions will not be represented in the solution set.
- Solutions are discrete, rather than continuous, therefore, the results of variations outside of the solution set are unknowable, without modeling them.
- Unable to address the interactions of larger, more complex and interrelated systems.

Deterministic modeling was selected for this study due to the limitations on delivery time, cost of study and amount of historic data available.

Scenarios – Descriptions of a set of input conditions that are applied to a production costing model to evaluate how a system will behave under that set of conditions. The input variables defined in the various scenarios in this study include natural gas price, electric market price and load volume. Due to the short term nature of this study (one year) and the relative stability of coal prices recently, coal price was assumed constant. For this study a total of nine (9) scenarios have been considered, as described below:

Scenario 1 - Expected Case– This scenario represents the most likely conditions based on what is currently known about market conditions for the study period.

- Natural gas price is set at the monthly expected value of the EIA short term forecast model. The use of monthly prices could understate the volatility of the model slightly, but given the use of the model, the cost of development of a daily volatility model was not worthwhile.
- MISO market price is set at the forward price curve. Due to the availability of products in the market at this time, pricing for December 2014 was unavailable and has been estimated based on available data. Hourly volatility of the market and the daily price shape is estimated using historic MISO data. This data is then adjusted to set the average price to the market forecast.
- Load volume is set to the load provided for the TCLP system. Hourly load volatility is set to the same base year as the market prices to estimate the effect of load volatility on the system, while maintaining the effect of correlation between load and market price caused by weather events.

Events where Load and Market Prices are not Correlated – Certain events can occur in energy markets which are uncorrelated with system load, but can have an impact on cash flow. An example of this type of event is a movement in natural gas price which typically causes a correlated move in electric prices, but typically does not affect native load.

Scenario 2 - Moderate Market Increase – This scenario represents the effect of a moderate price increase without a change in the underlying system energy consumption.

- Natural gas price increased by ½ of the EIA high gas case
- MISO market price increase proportionate to the increase in natural gas price
- Load volume unchanged from expected case

Scenario 3 - Large Market Increase – This scenario represents the effect of a large price increase without a change in the underlying system energy consumption.

- Natural gas price increased to the EIA high gas case

- MISO market price increase proportionate to the increase in natural gas price
- Load volume unchanged from expected case

Scenario 4 - Moderate Market Decrease – This scenario represents the effect of a moderate price decrease without a change in the underlying system energy consumption.

- Natural gas price decrease by ½ of the EIA low gas case
- MISO market price decrease proportionate to the decrease in natural gas price
- Load volume unchanged from expected case

Scenario 5 - Large Market Decrease – This scenario represents the effect of a large price decrease without a change in the underlying system energy consumption.

- Natural gas price decrease to the EIA low gas case
- MISO market price decrease proportionate to the decrease in natural gas price
- Load volume unchanged from expected case

Events where Load and Market Prices are Correlated – As opposed to the events described above, Traverse City can also experience events that have correlated effects where load, fuel prices and market prices move together. An example of this is an extended departure from normal weather. Since marginal prices in MISO tend to follow the marginal price of natural gas, these scenarios move the fuel and power market proportionally.

Scenario 6 - Moderate Correlated Increase - This scenario represents the effect of a moderate load increase correlated with an increase in the underlying market conditions.

- Natural gas price increased by ½ of the EIA high gas case
- MISO market price increase proportionate to the increase in natural gas price
- Load volume increased by 1.5%

Scenario 7 - Large Correlated Increase - This scenario represents the effect of a large load increase correlated with an increase in the underlying market conditions.

- Natural gas price increased to the EIA high gas case
- MISO market price increase proportionate to the increase in natural gas price
- Load volume increased by 3%

Scenario 8 - Moderate Correlated Decrease - This scenario represents the effect of a moderate load decrease correlated with a decrease in the underlying market conditions.

- Natural gas price decrease by ½ of the EIA low gas case
- MISO market price decrease proportionate to the decrease in natural gas price
- Load volume decreased by 1.5%

Scenario 9 - Large Correlated Decrease - This scenario represents the effect of a large load decrease correlated with an increase in the underlying market conditions.

- Natural gas price decrease to the EIA low gas case
- MISO market price decrease proportionate to the decrease in natural gas price
- Load volume decreased by 3%

Cash Flow – Net cash flow is the metric typically used to evaluate the risk to a system with load and generation assets. As opposed to production cost, net cash flow recognizes the natural hedge that load serving utilities have to volumetric risks such as weather events. Models that ignore load revenue tend to provide distorted views of a utilities risk profile and can lead to detrimental hedging decisions.

Cash flow measures generally include all of the variable revenues and costs associated with the components of the portfolio being analyzed. When converting this measure to a budget or power supply cost measure, it is common to include a fixed cost adjustment to the net variable cash flow, such that the cash flow numbers being evaluated are more typical of the complete cash flows that the decision makers are used to seeing. Because much of the fixed cost structure of the utility is unknown to those outside its operations, this adjustment is typically performed by the utility after the study is complete. This fixed cost adjustment is not relevant to the risk analysis, but can make the cash flows more meaningful to the decision maker, when they are in the range of the cash flows that they expect to see.

Typical components of the net variable cash flow include the variable components of: revenue from retail load (energy and/or demand), revenue from off-system sales, variable operations and maintenance expenses of operating generation units, the expense of off-system purchases, the expense of purchasing fuel, the revenue from excess fuel sales, the expense of procuring transmission and transportation, etc. Typically any sunk costs or revenues would be included in the fixed cost adjustment performed by the utility. A graphical example of how these charges combine to create a cash flow can be seen in Figure 1.

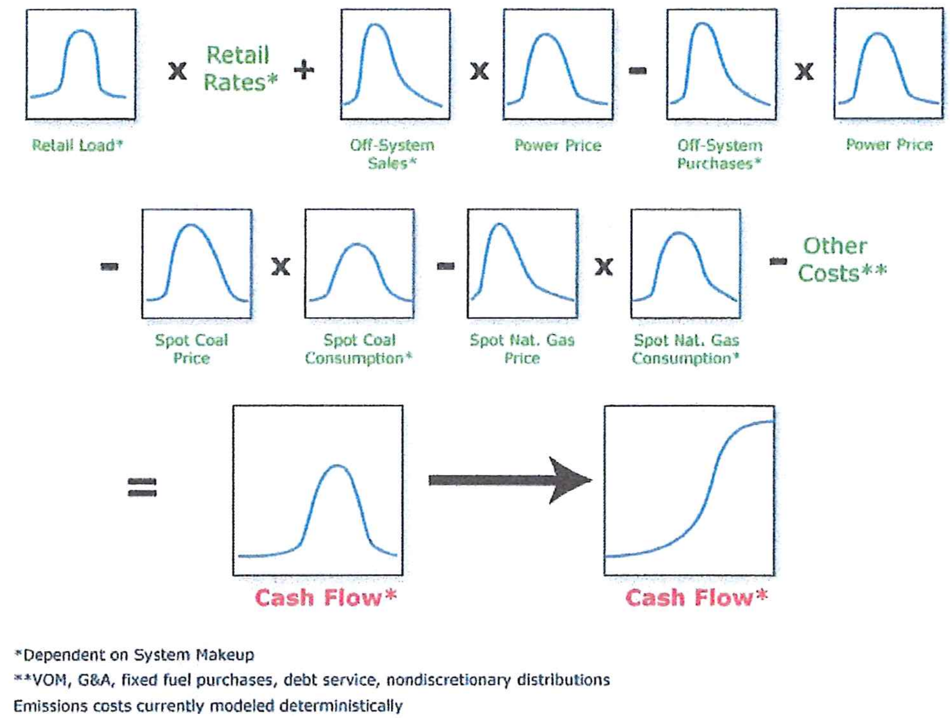

Figure 1 - Cash Flow Calculation Example

Risk Measures - The energy industry primarily utilizes two classes of risk management metrics to measure the exposure of a utility portfolio to risk: Value at Risk (VaR) and Cash Flow at Risk (CFaR).

Value at Risk (VaR) - Measures the maximum potential change in the value of a portfolio, during a specified period of time, with a specified degree of confidence. VaR is generally measured over very short time horizons of one to a few days. Therefore, a 10 day VaR 95% of $ x-amount would correspond to there being a 95% probability that the value of the portfolio will decrease by less than $ x-amount over the next 10 day period. Conversely, there is a 5% probability that the value of the portfolio will decrease by more than $ x-amount over the next 10 day period. VaR measures were developed by the financial trading markets and are widely used in purely financial markets (like the stock, bond, and money markets) where there is a very high degree of liquidity and almost any position can be liquidated within the VaR reporting period being monitored. Physical asset portfolios typically have very poor liquidity. Because VaR looks at such a short time horizon and assumes high liquidity, it is generally considered an excellent measure for primarily financial asset, easily liquidated portfolios and a poor risk measure for mostly physical asset, illiquid portfolios.

Cash Flow at Risk (CFaR) - Measures the maximum shortfall in cash flow (below a target level), during a specified period of time, with a specified degree of confidence. Due to the nature of CFaR being used to monitor the risk involved in holding illiquid assets, CFaR is generally measured over time horizons of months or years. Therefore, a 12 month CFaR 95% of $ y-amount would correspond to there being a 95% probability that the cash flow generated by a portfolio of assets will not be less than $ y-amount below the target value at the end of the 12 month period. Note that CFaR does not indicate how bad cash flow can get during that 12 month period, but that at the end of the period, there is a 95% probability that the good and bad cash flows that occur will net out to no less than $ y-amount short of the targeted value. CFaR assumes that all positions are held to delivery and is better suited to measuring the risks of holding portfolios of physical assets and illiquid commodities.

Due to this study being deterministic in nature, rather than stochastic, rather than using a continuous distribution with the 95% confidence interval defining the lower bound for cash flow at risk, the worst case scenario is used to define this measure.

A graphical example of Cash Flow at Risk is shown in Figure 2.

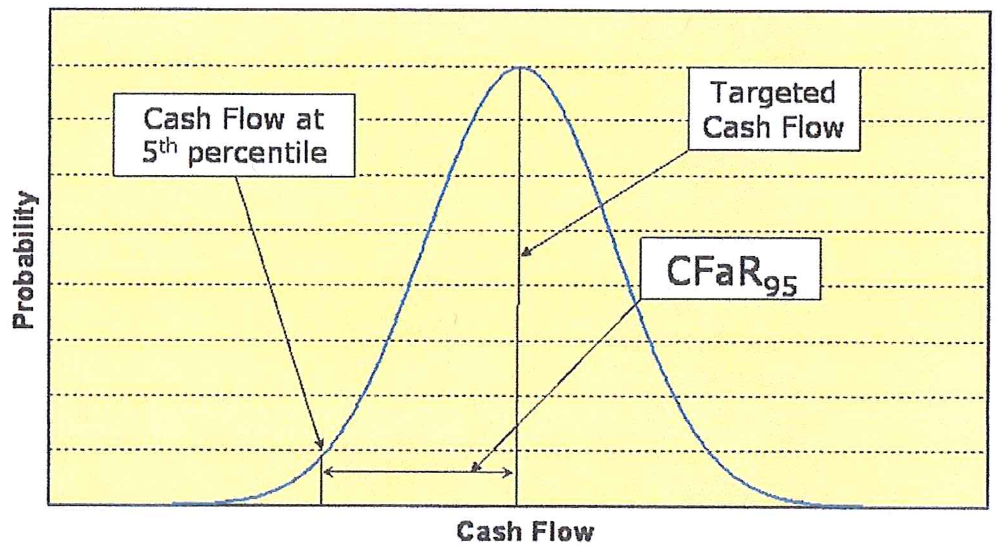

Figure 2 - Cash Flow at Risk Example

As stated above, CFaR is measured relative to a target value. In its most general usage, this target value is typically set to the expected value of the cash flow distribution of the reference system being evaluated. In the more specific case of measuring Budgeted Cash Flow at Risk (BCFaR), the target is changed to be the budgeted value that is of interest.

For the purpose of this assessment, the study will be measuring Net Cash Flow and Net Cash Flow at Risk. The target value for these measures is the cash flow of the current portfolio with only the minimum volumes taken from the Lansing Block Agreements. In future studies, if TCLP chooses establish a Budget Cash Flow Target, then that budget value would become the cash flow target each budget period. Assessment of that budget target is beyond the scope of this assessment. The target for this assessment is the cash flow of the current portfolio.

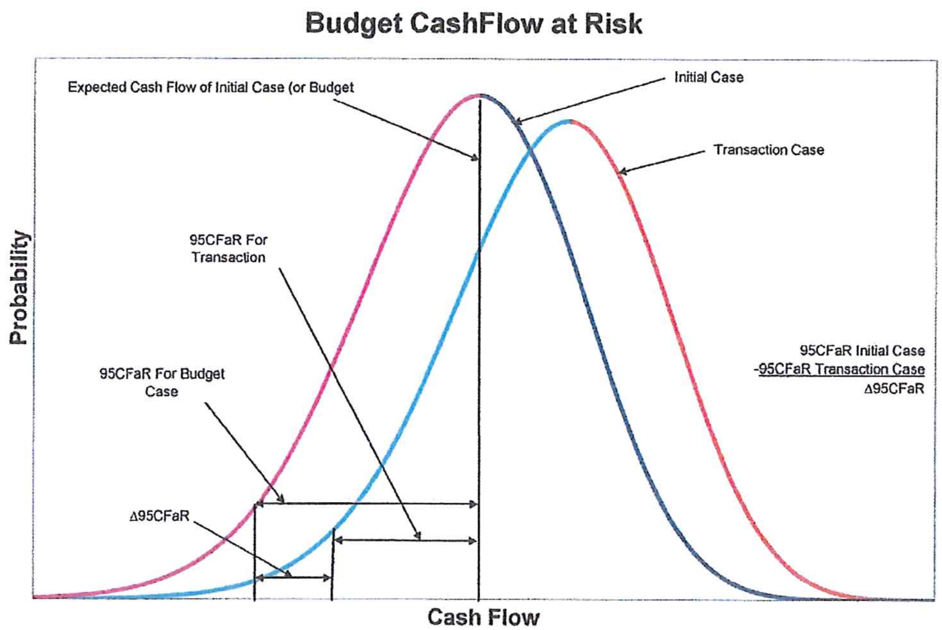

Figure 3 - Budget Cash Flow at Risk Example

Risk Metrics – This study uses two primary determinants for determining whether a combination of resources in a portfolio is preferable to another combination of resources, cash flow and cash flow at risk. It also uses the absolute value of the ratio of cash flow at risk to cash flow to compare the magnitude of the risk to reward tradeoff.

- An increase in net cash flow is favorable.
- A decrease in cash flow at risk is favorable.
- If net cash flow increases and cash flow at risk decreases, the change is considered favorable.
- If net cash flow decreases and cash flow at risk increases, the change is considered unfavorable.
- If cash flow increases while cash flow at risk decreases, the ratio of risk (cash flow at risk) to reward (net cash flow) is compared to the ratio of the expected case to determine if the reduction in risk is worth the cost of the hedge.
- If cash flow decreases while cash flow at risk increases, the ratio of risk (cash flow at risk) to reward (net cash flow) is compared to the ratio of the expected case to determine if the increase in risk is worth the increase in expected cash flow.

System Modeling

General Model Description

The TCLP portfolio includes all resources (generation and contract purchases) and obligations (load and contract sales) provided by TCLP, Lansing and MPPA, with the exception of the wind resources. The wind resources were not included since there was no need for TCLP to incur the cost of a wind forecast model, since operation of wind resources in an RTO market is typically one of a price taker and does not affect the dispatch of the system. All generators and loads are cleared in the market at the local spot price. Purchase and sale markets are unconstrained volumetrically and allow full interchange of power to and from the market.

- The real-time electric markets are structured to reflect non-firm energy markets. These markets provide no capacity (or ancillary services) and respond to reliability events that would adversely affect the system.
- All unit operation is cost based. Costs are defined as all variable costs associated with the production of power including: variable fuel cost, variable cost of emissions, variable cost of operations and maintenance, and any other cost identified by the member as relating directly to the number of unit startups and shutdowns or to the MWh's of generation delivered from the unit.
- In order to constrain study cost, the effect of forced outages was excluded from the modeling effort.
- Any relevant emissions costs are assumed to be in the pricing information provided.

Table 2 - Current System Capacity Balance

MISO requires TCLP to own or contract for capacity for their peak monthly load plus a 15% reserve margin. Based on the information provided in the MPPA 2014 Model, the following capacity balance has been prepared for the TCLP system.

Capacity Balance		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Peak Load		50.9	50.6	49.9	47.7	49.3	61.9	58.9	60.8	57.9	51.1	47.7	49.6
Reserves	15%	7.6	7.6	7.5	7.2	7.4	9.3	8.8	9.1	8.7	7.7	7.2	7.4
Requirement		**58.5**	**58.2**	**57.3**	**54.9**	**56.7**	**71.1**	**67.7**	**70.0**	**66.5**	**58.8**	**54.8**	**57.1**
Belle River		10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Campbell 3		10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Kalkaska CT		36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9
Renewables		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total		**58.5**	**58.5**	**58.5**	**58.5**	**58.5**	**58.5**	**58.5**	**58.5**	**58.5**	**58.5**	**58.5**	**58.5**
Capacity Deficit *		**0.0**	**0.3**	**1.2**	**3.6**	**1.8**	**-12.6**	**-9.2**	**-11.5**	**-8.0**	**-0.3**	**3.7**	**1.4**

- A negative capacity indicates a capacity deficit. Capacity deficit should be filled through Lansing contract or through external supplier
- Peak load and unit capacity per the load forecast in the MPPA 2014 Traverse City Model
- Reserve requirement per Beck IRP

Observation

Does TCLP have sufficient capacity to support their capacity obligations?

TCLP has sufficient capacity 7 of 12 months utilizing their currently owned/contracted resources. The TCLP capacity balance shows a capacity deficit, during June through October, of up to 12.6 MW that will require contracting through an external party. These may be filled via Lansing contract or through another external provider.

Current System Risk Profile

The current portfolio has an expected cash flow of between $1 and $1.6 million per month and a cash flow at risk of less than $58,000 for most months. Overall the CFaR for this portfolio appears to be fairly low, due to the limited dispatchability of the portfolio and the quantity of fixed resources available. It is important to note, however, that this low CFaR is an artifact of the construction of the portfolio and will become significantly larger once the current contracts have expired. CFaR in a portfolio is a measure of the uncertainty of future cash flows. When a portfolio is highly constrained, cash flows become highly predictable. The constraints built into this portfolio are primarily due to the mix of resources supplying the obligations. The resources are primarily contract power operated by other parties, with limited operating flexibility. Hence, TCLP is not able to gain any of the operational flexibility of determining which resources should be committed for the operating environment. As a result, cash flows become constrained and it is likely that operating costs are higher than would be realized if this operating flexibility were present. Depending on the terms of the relevant contracts, TCLP may not be exposed to other operating uncertainties such as labor costs, maintenance costs, etc.

Observation

What is the risk of riding on the MISO spot market?

Based on the tight constraints of the current portfolio and the strong hedge provided by the Kalkaska CT, the risk of riding on the MISO spot market is fairly low in all of the scenarios studied.

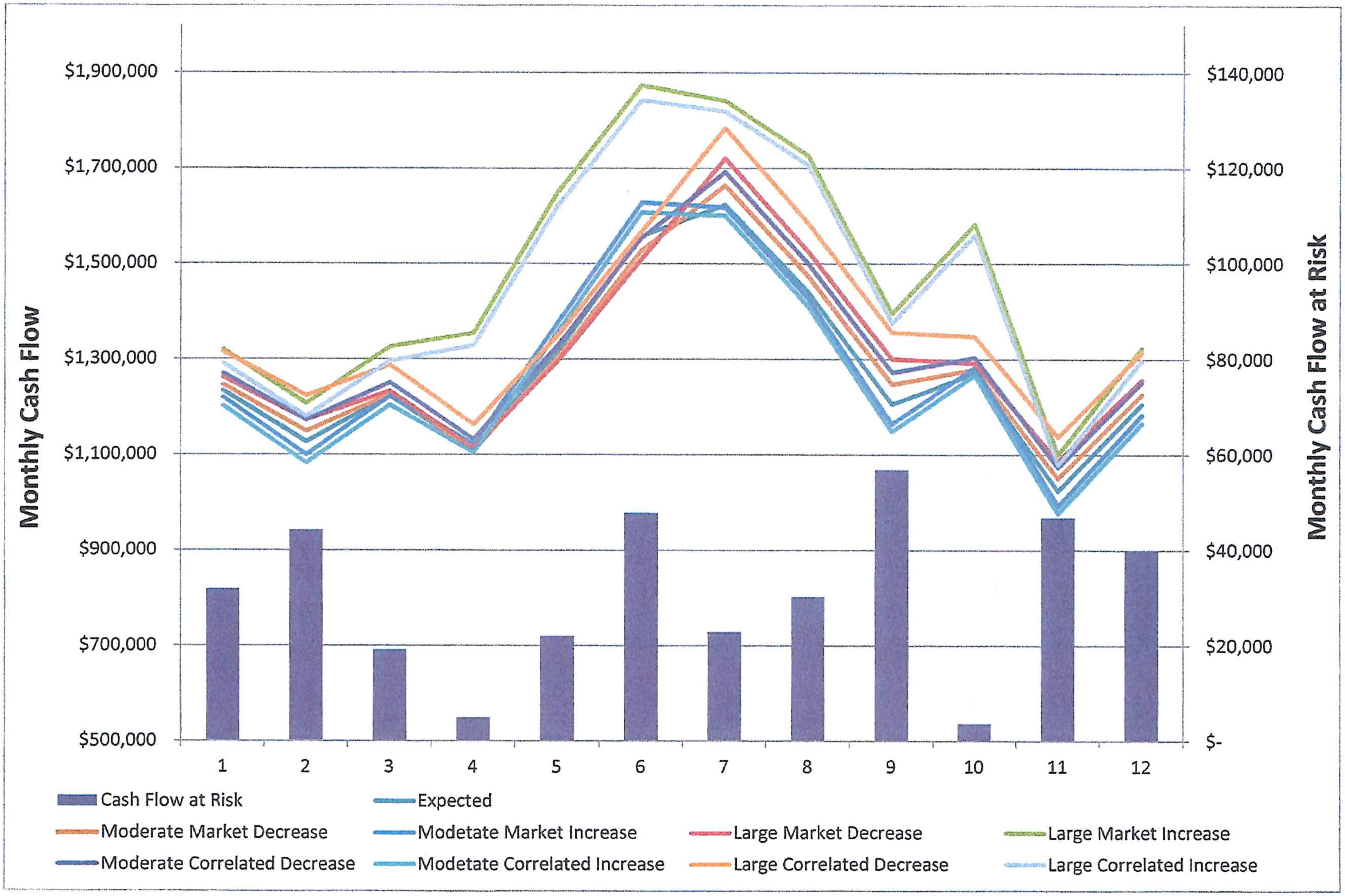

Figure 4 - Monthly Cash Flow for Various Scenarios

Electric Energy Market Modeling

Spot Market

The electric energy market model is made up of spot purchase and sale markets designed to represent the behavior of the hourly spot markets. The electric energy markets are modeled based on historic hourly behavior. The expected value of the electric energy markets has been set to the forward price curve at the Michigan Hub and localized to other nodes by using historic marginal congestion and marginal losses in the MISO market. The uncertainty in the electric price markets is based on historic data from the MISO market.

Potential Forward and/or Option Contracts

Potential forward and/or option contracts have been evaluated for purchase of electricity during each month of the study. The contracts analyzed are for the purchase of financial and physical electric blocks of power. The specific contracts analyzed include increasing the quantities taken under the Lansing Base, Option and Peaking Option contracts, financial forward contracts at the Michigan Hub and monthly financial option contracts at the Michigan Hub. Results of these analyses are provided in the results section below.

Analysis of Potential Electric Contracts

Table 3 – Purchase of Additional Quantities under the Lansing Purchase Power Agreement

The following table demonstrates the results of the analysis of taking additional quantities of power from the Lansing Base Block, Peaking Block and Peaking Option Block Contracts. Line one shows the analysis results of the current portfolio with all TCLP units and the minimum contract quantities from the Lansing Purchase Power Agreement. Subsequent lines detail the analysis of increasing the quantities of the base block, peaking block and each monthly peaking option block.

Scenario Cash Flow	Scenario Cash Flow at Risk	Change in Cash Flow	Change in CFaR	Ratio	Base Block	Option Block	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12	
15,336,590	210,554				10	7													Current Portfolio
14,115,878	1,932,816	(1,220,713)	1,722,262	141%	20	7													Base Block
14,693,082	700,263	(643,508)	489,709	76%	10	15													Peaking Block
15,244,283	273,954	(92,307)	63,400	69%	10	7	10												Peaking Option Block
15,247,772	270,148	(88,818)	59,594	67%	10	7		10											Peaking Option Block
15,239,937	272,085	(96,653)	61,531	64%	10	7			10										Peaking Option Block
15,234,681	275,632	(101,910)	65,078	64%	10	7				10									Peaking Option Block
15,250,132	256,962	(86,459)	46,407	54%	10	7					10								Peaking Option Block
15,252,529	257,129	(84,061)	46,574	55%	10	7						10							Peaking Option Block
15,283,910	217,937	(52,680)	7,383	14%	10	7							10						Peaking Option Block
15,271,973	233,602	(64,618)	23,047	36%	10	7								10					Peaking Option Block
15,249,146	260,429	(87,444)	49,875	57%	10	7									10				Peaking Option Block
15,233,480	269,800	(103,111)	59,245	57%	10	7										10			Peaking Option Block
15,249,984	265,214	(86,6072)	54,659	63%	10	7											10		Peaking Option Block
15,235,335	273,411	(101,256)	62,856	62%	10	7												10	Peaking Option Block

The best value for the utility is the base case - In all instances, net cash flow decreases in the expected scenario (the contracts all have a net cost to the utility above the prices returned by the market) and cash flow at risk increases (the utility incurs additional price risk by engaging in the contract).

Analysis of Potential Electric Contracts

Table 4 - Purchase of Financial Forward Contracts at the Michigan Hub

The following table demonstrates the results of the analysis of purchasing a financial forward contract, delivered to the Michigan Hub, for each of the study months, as well as a financial forward strip made up of all of the study months.

Scenario Cash Flow	Scenario Cash Flow at Risk	Change in Cash Flow	Change in CFaR	Ratio	Base Block	Option Block	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12	
15,336,590	210,554				10	7													Current Portfolio
15,336,683	181,554	92.93	(29,000)	31,206%	10	7	10												TEA 5x16
15,336,572	181,348	(18.53)	(29,206)	157,656%	10	7		10											TEA 5x16
15,336,537	175,485	(52.99)	(35,069)	66,182%	10	7			10										TEA 5x16
15,336,761	173,552	170.27	(37,002)	21,731%	10	7				10									TEA 5x16
15,336,652	170,442	61.37	(40,113)	65,359%	10	7					10								TEA 5x16
15,336,529	173,129	(61.49)	(37,426)	60,865%	10	7						10							TEA 5x16
15,336,710	165,137	119.98	(45,417)	37,852%	10	7							10						TEA 5x16
15,336,552	169,022	(38.32)	(41,532)	108,387%	10	7								10					TEA 5x16
15,336,506	173,069	(84.47)	(37,485)	44,378%	10	7									10				TEA 5x16
15,336,520	166,760	(70.94)	(43,795)	61,737%	10	7										10			TEA 5x16
15,336,624	178,574	33.18	(31,981)	96,387%	10	7											10		TEA 5x16
15,336,535	172,211	(55.72)	(38,344)	68,809%	10	7												10	TEA 5x16
15,336,686	100,926	95.29	(109,629)	115,053%	10	7	10	10	10	10	10	10	10	10	10	10	10	10	TEA 5x16

Net cash flow for these scenarios hover around break even in the expected scenario (differences are round off errors) since the forward prices for the contracts are set at the same price as the values used for the price forecast. This also validates that the model is operating correctly as designed. Cash flow at risk decreases for each of the contracts. Note that the change in cash flow is additive when contracts are chained, but cash flow at risk is not additive since all not all of the risks and benefits occur in the same scenario.

Analysis of Potential Electric Contracts

Table 5 - Purchase of Financial Option Contracts at the Michigan Hub - $2.00 Out of the Money

The following table demonstrates the results of the analysis of purchasing a financial option contract, delivered to the Michigan Hub, for each of the study months, as well as a financial forward strip made up of all of the study months.

Scenario Cash Flow	Scenario Cash Flow at Risk	Change in Cash Flow	Change in CFaR	Ratio	Base Block	Option Block	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12	
15,336,590	210,554				10	7													Current Portfolio
15,330,078	195,986	(6,512)	(14,568)	224%	10	7	10												TEA $2 OTM
15,329,582	193,956	(7,008)	(16,598)	237%	10	7		10											TEA $2 OTM
15,330,845	187,111	(5,746)	(23,444)	408%	10	7			10										TEA $2 OTM
15,330,677	186,506	(5,914)	(24,048)	407%	10	7				10									TEA $2 OTM
15,329,770	183,142	(6,821)	(27,412)	402%	10	7					10								TEA $2 OTM
15,328,997	187,442	(7,594)	(23,112)	304%	10	7						10							TEA $2 OTM
15,324,306	184,462	(12,285)	(26,092)	212%	10	7							10						TEA $2 OTM
15,325,738	187,334	(10,853)	(23,220)	214%	10	7								10					TEA $2 OTM
15,327,317	189,063	(9,274)	(21,492)	232%	10	7									10				TEA $2 OTM
15,329,451	181,259	(7,139)	(29,295)	410%	10	7										10			TEA $2 OTM
15,331,058	191,706	(5,533)	(18,848)	341%	10	7											10		TEA $2 OTM
15,325,074	169,027	(11,517)	(41,528)	361%	10	7												10	TEA $2 OTM
15,246,100	90,491	(90,491)	(120,064)	133%	10	7	10	10	10	10	10	10	10	10	10	10	10	10	TEA $2 OTM

In all instances, net cash flow decreases in the expected scenario (the contracts all have a net cost to the utility above the prices returned by the market) since the options all require a premium to be paid and are not triggered in the expected scenario. Cash flow at risk decreases for each of the contracts, because when prices become high, the contracts are triggered and become valuable. Note that the change in cash flow is additive when contracts are chained, but cash flow at risk is not additive since all not all of the risks and benefits occur in the same scenario.

Analysis of Potential Electric Contracts

Table 6 - Purchase of Financial Option Contracts at the Michigan Hub - $5.00 Out of the Money

The following table demonstrates the results of the analysis of purchasing a financial option contract, delivered to the Michigan Hub, for each of the study months, as well as a financial forward strip made up of all of the study months.

Scenario Cash Flow	Scenario Cash Flow at Risk	Change in Cash Flow	Change in CFaR	Ratio	Base Block	Option Block	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12	
15,336,590	210,554				10	7													Current Portfolio
15,332,894	203,730	(3,696)	(6,824)	185%	10	7	10												TEA $5 OTM
15,332,462	200,676	(4,128)	(9,878)	239%	10	7		10											TEA $5 OTM
15,333,600	194,436	(2,990)	(16,119)	539%	10	7			10										TEA $5 OTM
15,333,422	194,320	(3,168)	(16,234)	512%	10	7				10									TEA $5 OTM
15,332,726	190,266	(3,864)	(20,289)	525%	10	7					10								TEA $5 OTM
15,331,954	194,566	(4,637)	(15,989)	345%	10	7						10							TEA $5 OTM
15,327,896	191,432	(8,694)	(19,123)	220%	10	7							10						TEA $5 OTM
15,328,997	194,155	(7,594)	(16,399)	216%	10	7								10					TEA $5 OTM
15,330,442	196,018	(6,149)	(14,537)	236%	10	7									10				TEA $5 OTM
15,332,579	189,171	(4,011)	(21,383)	533%	10	7										10			TEA $5 OTM
15,333,368	198,516	(3,222)	(12,038)	374%	10	7											10		TEA $5 OTM
15,333,070	195,971	(3,520)	(14,584)	414%	10	7												10	TEA $5 OTM
15,280,917	55,674	(55,674)	(154,881)	278%	10	7	10	10	10	10	10	10	10	10	10	10	10	10	TEA $5 OTM

In all instances, net cash flow decreases in the expected scenario (the contracts all have a net cost to the utility above the prices returned by the market) since the options all require a premium to be paid and are not triggered in the expected scenario. Cash flow at risk decreases for each of the contracts, because when prices become high, the contracts are triggered and become valuable. Note that the change in cash flow is additive when contracts are chained, but cash flow at risk is not additive since all not all of the risks and benefits occur in the same scenario.

Analysis of Potential Electric Contracts

Table 7 - Purchase of Financial Option Contracts at the Michigan Hub - $7.00 Out of the Money

The following table demonstrates the results of the analysis of purchasing a financial option contract, delivered to the Michigan Hub, for each of the study months, as well as a financial forward strip made up of all of the study months.

Scenario Cash Flow	Scenario Cash Flow at Risk	Change in Cash Flow	Change in CFaR	Ratio	Base Block	Option Block	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12	
15,336,590	210,554				10	7													Current Portfolio
15,334,021	209,643	(2,570)	(911)	35%	10	7	10												TEA $7 OTM
15,333,678	205,860	(2,912)	(4,694)	161%	10	7		10											TEA $7 OTM
15,334,675	200,080	(1,915)	(10,474)	547%	10	7			10										TEA $7 OTM
15,334,549	200,234	(2,042)	(10,320)	506%	10	7				10									TEA $7 OTM
15,333,902	195,810	(2,688)	(14,745)	549%	10	7					10								TEA $7 OTM
15,333,298	199,942	(3,293)	(10,613)	322%	10	7						10							TEA $7 OTM
15,329,726	196,641	(6,864)	(13,913)	203%	10	7							10						TEA $7 OTM
15,330,710	199,162	(5,880)	(11,393)	194%	10	7								10					TEA $7 OTM
15,332,054	201,125	(4,536)	(9,429)	208%	10	7									10				TEA $7 OTM
15,333,757	195,353	(2,834)	(15,201)	536%	10	7										10			TEA $7 OTM
15,334,310	203,654	(2,280)	(6,901)	303%	10	7											10		TEA $7 OTM
15,334,126	201,955	(2,464)	(8,600)	349%	10	7												10	TEA $7 OTM
15,296,314	93,361	(40,277)	(117,194)	291%	10	7	10	10	10	10	10	10	10	10	10	10	10	10	TEA $7 OTM

In all instances, net cash flow decreases in the expected scenario (the contracts all have a net cost to the utility above the prices returned by the market) since the options all require a premium to be paid and are not triggered in the expected scenario. Cash flow at risk decreases for each of the contracts, because when prices become high, the contracts are triggered and become valuable. Note that the change in cash flow is additive when contracts are chained, but cash flow at risk is not additive since all not all of the risks and benefits occur in the same scenario.

Observation

What are the appropriate contract volumes strikes for the Lansing Base Block, Peaking Block and Peaking Option Block contracts?

How do different contract choices affect the cash flow and risk profile of the portfolio?

Each of the Lansing contract options decreases net cash flow and increases risk for the TCLP portfolio. These are both unfavorable to the portfolio. Taking additional quantities from the Lansing contract in not recommended.

Observation

What options are available to displace additional Lansing contract volumes and/or MISO spot transactions?

How do different contract choices affect the cash flow and risk profile of the portfolio?

Each of the Michigan Hub forward contracts is ideally cash flow neutral for the expected case and reduces cash flow at risk in the most unfavorable scenario. Each of the options contracts cost the utility some of its net cash flow (the option premium) and reduces cash flow at risk in the most unfavorable scenario. While technically beneficial, due to the limited amount of risk in the current portfolio, adding any of these contracts to the current portfolio is not recommended.

Guidelines to consider when taking portfolio positions in ISO markets

While we strongly believe that detailed resource modeling is the prudent method of evaluating system risk tradeoffs, the following guidelines identify some of the key risks that were observed in the modeling.

- Real-time prices are significantly more volatile than either day-ahead or forward. As a result, transacting the base load portion of the portfolio in forward markets tends to reduce risk.
- During periods when system cost is near market prices or there is large volumetric uncertainty (daily peaks), forward transactions tend to add risk to the portfolio. This effect is due to the margins on a spot trade being relatively stable while on a forward transaction, one leg of the trade becomes fixed and may become stranded in actual practice. With the risk of fuel price movement and the chance of a forced outage, system risk increases. A portion of this effect can be mitigated by locking fuel prices at the same time that a forward sale is transacted.
- This study evaluates the quantity of transactions that are recommended to mitigate risk. It does not look at when those transactions should be made. Much of the research available indicates that it is prudent to programmatically place hedges on over a period of time (this is a form of diversification), such that a single market event does not adversely impact the portfolio value.
- As contract resources are replaced, keep in mind that the modern ISO markets pay well for portfolio flexibility. Being able to commit and de-commit units, having highly dispatchable assets or contracts, and having wide dispatch ranges are favorable in these markets.
- It is typically favorable to keep hedged fuel volumes in quantities and time periods typically consumed and below the expected consumption levels. Over-hedging can add as much risk to a portfolio as under-hedging.
- Portfolio diversification through time is beneficial to the portfolio. Keep some of the portfolio in the forward markets, some in the near term markets and some in the real-time markets to optimize portfolio performance. Layer in purchase contracts over time, rather than reacting to adverse events or trying to time the market.

While these guidelines do not replace risk modeling, they do provide some rules of thumb that can reduce the overall risk to a portfolio.

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100 YEARS
TRAVERSE CITY
LIGHT & POWER

To: **Light & Power Board**
From: Jessica Wheaton, Marketing & Community Relations Coordinator
Date: September 18, 2013
Subject: Customer Outage Feedback Survey

TCL&P staff uses the bi-annual, statistically significant customer satisfaction survey to gage overall customer satisfaction when it comes to items such as rates and reliability, but we believe it would also be beneficial to have some real-time data reflecting customer satisfaction after an electrical power outage. Therefore, staff has developed a short survey that would request customer feedback after they experience an outage.

Because it would be too administratively burdensome to ask for feedback after every outage, staff will select approximately one outage every quarter to follow up on. Staff will send out a postcard to customers notifying them why the outage occurred and request their feedback by taking a brief online survey.

Attached is the draft postcard communication and online survey. It is staff's hope to implement this feedback tool by the end of 2013.

TCL&P Electrical Power Outage Feedback

Dear Valued Customer,

Recently you experienced an electrical power outage at your home or business due to: ☐Equipment Failure ☐Animal ☐Tree ☐Car/Pole Accident ☐Weather

Traverse City Light & Power (TCL&P) would appreciate your feedback on how TCL&P crews responded to the outage and whether or not you were satisfied with any interaction you may have had with utility employees.

Please take a moment and participate in a brief survey found online at: www.tclp.org/OutageFeedback

Your feedback will assist TCL&P with continuous improvement of customer service and help us better serve all of our customers. Please contact TCL&P at 231-922-4940 with any questions.

Thank you,
TCL&P Department

TCL&P Electrical Power Outage Feedback

***1. Please rate your overall level of satisfaction regarding TCL&P's response to the power outage?**

- Very Satisfied
- Satisfied
- Neutral
- Dissatisfied
- Very Dissatisfied

***2. Did you call in and report the power outage to TCL&P's 24-hour dispatch center?**

- Yes
- No
- Tried, but could not get through

3. If yes to question 2, please rate your level of satisfaction regarding your interaction with the dispatcher?

- Very Satisfied
- Satisfied
- Neutral
- Dissatisfied
- Very Dissatisfied

***4. Did you have any interaction with a TCL&P field crew (example: linemen) during the power outage?**

- Yes
- No

5. If yes to question 4, please rate your level of satisfaction regarding your interaction with the field crew?

- Very Satisfied
- Satisfied
- Neutral
- Dissatisfied
- Very Dissatisfied

6. Please provide any additional feedback regarding the power outage that would be beneficial for TCL&P.

7. If you would like a TCL&P representative to follow up with you regarding the recent power outage, please provide the following information:

Name:

Address:

Email Address:

Phone Number:

Done