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MAXsys Elite

Quick Start Guide

0713070958-MKB Rev. L

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Document History

Title: MAXsys Elite Multifunction Electronic Meters and IED's Quick Start Guide

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Rev	Date Issued	Description of Revision
1.00	5/24/07	First issue
Rev. C		Added PQ defaults
Rev. D	7/11/08	Corrected RS485 2-wire pin-out J2
Rev. E	10/28/08	Added the switchboard meter connections.
Rev. F	3/17/09	Up-dated Switchboard meter connections.
Rev. G	3/19/09	Corrected switchboard pin-out.
Rev. H	4/2/09	Uppdated Drawing for RS232-1 (J1)
Rev. I	4/3/09	Added Appedix A, B, C and D
Rev. J	5/6/09	Added Appedix E, F,G,H Updated testing & TLC
Rev. K	7/2/09	Added Appedix I, corrected pinout for cable J8 And made changes to the TLC % losses. Added Appedix J external modem configuration.Appedix k Peer 2 Peer configuration.
Rev. L	11/10/09	Update section 9 testing and added Appedix L Sample Rates and data flow.

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MAXsys Elite Meter

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1. Firmware History

1.01 The history behind the Elite Meter started in 1990 with the Quad 4 meter running firmware version 1xxx. The next generation of the meter was the Quad 4 Plus meter. This meter started with porting all of the functions and tables from the Quad 4 meter into firmware version 07xx as more tables and functions were added additional firmware versions were added. As hardware and technology changed the next family of meters became the MAXsys 2510. This meter started with porting all of the functions and tables from the Quad 4 Plus meter into firmware version 27xx as more tables and functions were added additional firmware versions were also added. With additional changes of hardware the next family of firmware for the MAXsys meter was firmware version 57xx. This firmware started with porting all of the functions and tables from firmware 27xx. As new features and functions were added additional firmware versions were added. The next step in the growth of the MAXsys meter family is the Elite Meter running firmware version 7760. This firmware started by porting all of the functions and features of the 27xx firmware into the Elite firmware. With more memory and new technology we are now able to have all of the old tables and functions in one firmware version. The new firmware also has the new functions and features along with tables for the future. This allows the MAXsys Elite meter to have only one version of firmware.

2. Overview

2.01 The MAXsys Elite Meter is a 0.1 accuracy four quadrant meter with logic, control and advanced power quality functions. The meter supports all of the functions and features of the MAXsys 2510 except for dial encoders, NSP power quality and the socket sleuth function. The meter will also support all of the old option cards except for the old modems. The display card is the heart of the Elite meter. The main functions that are supported by this card are the user interface (display and menu buttons), CPU, measurement circuit, memory, 4- output relays (the output relay cable is an option). All of the communications ports except for the modem and Ethernet are also on the display card. The meter also allows you to turn on and move the advanced features using a Soft Key feature.

3. Standard Features

3.01 The MAXsys Elite Meter comes with an operating system that supports all of the functions and features of the MAXsys 2510 meters including single level Sag and Swell events and all of the new features of the MAXsys Elite meter. The following hardware options can be order and are not included in the standard meter package.

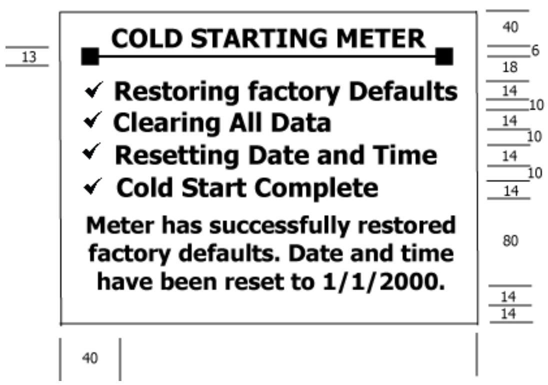
a. Output Relay cable
b. Modem card and cables
c. Analog card and cable
d. I/O card and cable
e. Protocol card and cable (Not Required for DNP or MODBUS)

The following functions can be turned on or moved between meters using the “soft key” feature (no hardware required).

a. Advanced Power Quality (Waveform, RMS and Harmonic capture along with 3 levels of Sag and Swells).
b. RTU functions (DNP and MODBUS)
c. Instrument Transformer corrections
d. Dual Recorder
f. Peer 2 Peer
g. IRIG-B

4. Quick Start

4.01 The MAXsys Elite Meter is ready to go out of the box using the default that comes in the meter. If you are going to create your on program using Mapper32 and one of the default templates you should do that at this time and put the program in the meter using MAXcom before continuing. The next step is to remove the cover of the meter and check the power source for the electronics of the meter. The meter should come from the factory set to power from “A” phase of the meter unless it was order as an auxiliary powered meter. At about the 11:00 a clock position of the transformer board (this is the board closes to the back of the meter. You will see a white connector that should have a plug with a red and a white wire. This would indicate the meter will power from phase “A” of the meter. There will also be another plug with a yellow and a brown wire this would be used if the is to be powered from an auxiliary power source AC or DC. The only other thing you will need to do is connect the battery plug to the back of the display card at the 12:00 a clock position. You can replace the cover and put the meter into service. You will see the meter going through its power up process on the screen.



After the meter comes up and the display is scrolling you will need to connect to the meter with MAXcom and set time. If you use RS232-1 port coming from the meter, remember that you will need a null modem between the meter and your computer. You can then use the navigation buttons to look at the meter menu system.

Navigation Buttons

Navigation Buttons and LCD Menus

The display can be controlled by four buttons on the cover of the meter. There is an “Enter” button, “Exit” button, and “Up and Down” buttons used for scrolling through the displays. During the normal display sequencing, the “main menu” will appear after pressing the Enter button on the front of the meter.

The submenus from the main menu are as follows:

Communications

Comm. 1 – RS232
Comm. 2 – RS232
Comm. 3 – RS232/485
Comm. 4 – RS232/485
Ethernet
Optical Port

Current Loop
IRIG – B

Diagnostics

Meter Info
Diagnostic Test
Vector Diagram
Error Codes
LCD Contrast
Accuracy Test

Displays

Normal
Alternate
Test Mode
Clear Error Codes

I/O Status

Load Profile

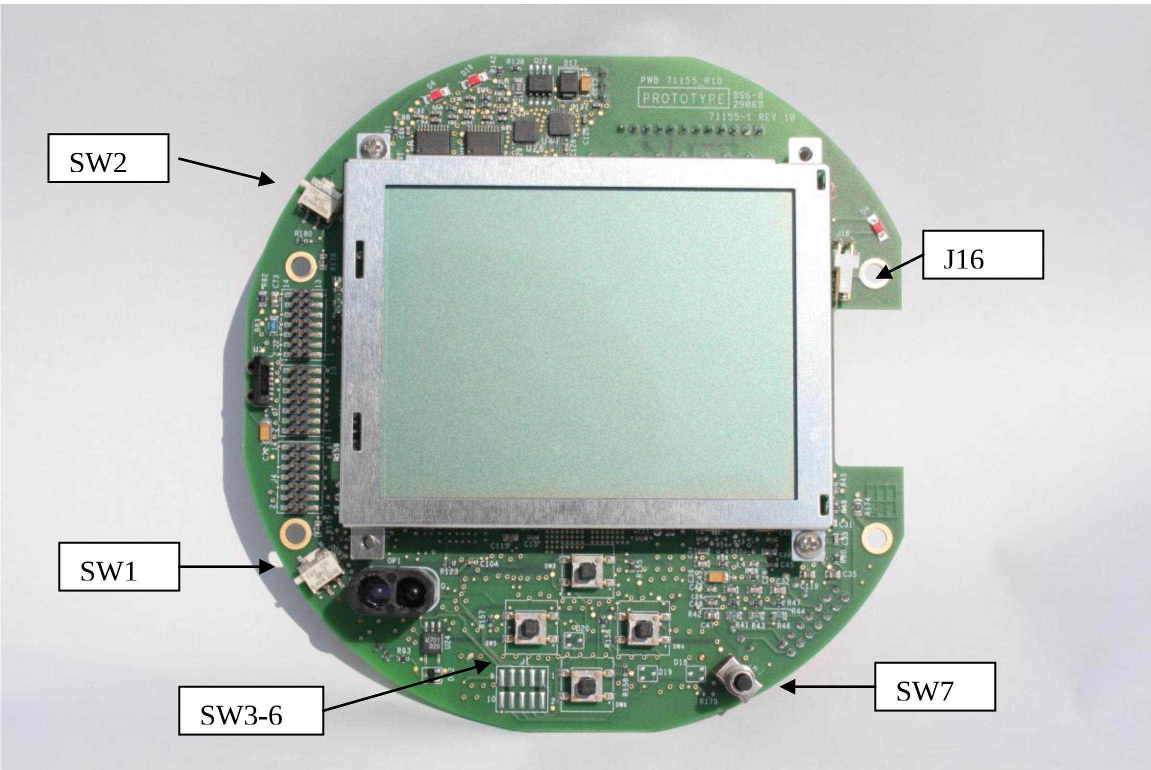
Power Quality

Waveforms
Harmonics
Sags & Swells

5. Meter Cards

5.01 Display Card

5.01.1 Layout and description (Front View)



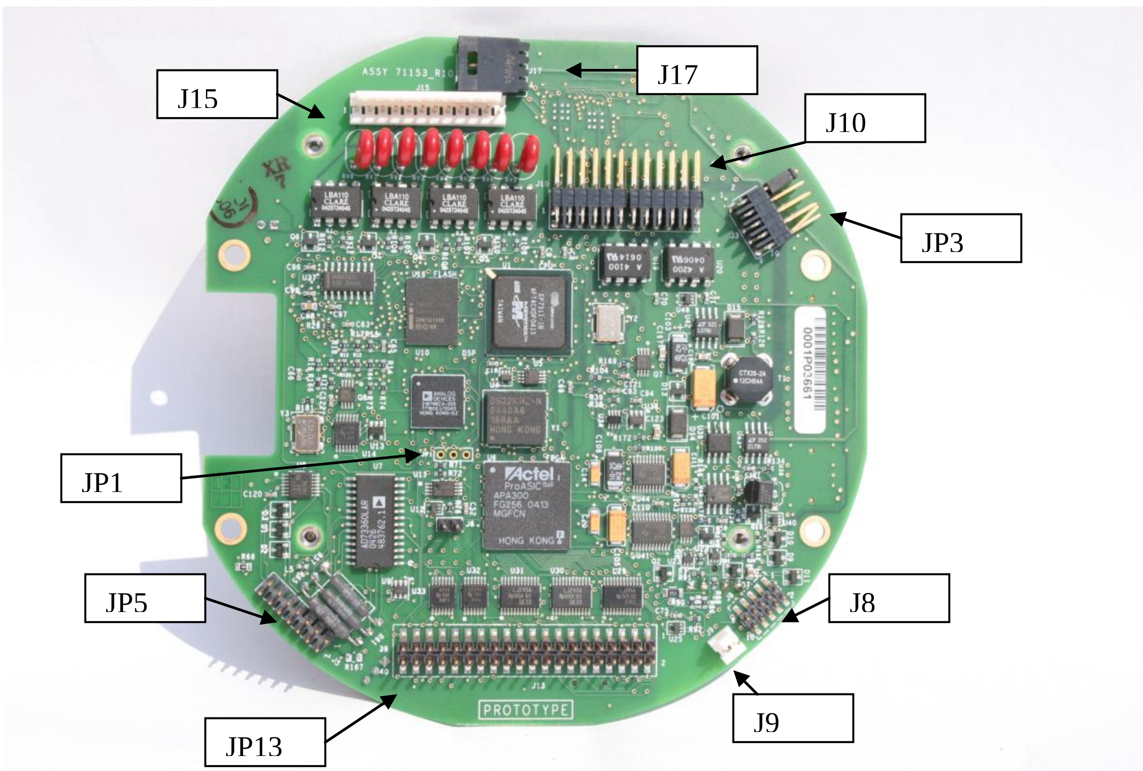
The display/CPU board has a total of 7 switches. Four of the switches make up the navigation button assembly which allows external access (of the meter) of a set of menus that will be displayed on the LCD.

1. SW 2 – This switch causes a System Reset to the Meter. This switch when used in conjunction with the other switches will cause either a cold reset that will restore factory defaults or a Program restart that will reset communication ports and restart the customers program.
2. SW 1 – Special function switch that will be used in conjunction with other switches to cause either a program restart, cold starts or enters Test Mode.

3. SW 7 –. Demand Reset. This switch performs the same function as the demand reset in the current MAXsys 2510 firmware.
4. SW 3 through 6 is for navigation of the menus and is accessible from the front of the meter.

Function	SW2	SW1	SW7	SW3	SW4	SW5	SW6	Description
Cold Start factory Defaults Restored	X	X	X					**Simultaneously press and hold S1 and S7. While holding momentarily press SW2. When screen displays message to release switches, remove hold on SW1 and SW7.**
System Reset Protect Data	X							**Momentarily press SW2**
Program Restart	X	X						**Press and hold SW1 while momentarily pressing SW2. When screen displays message to release switch, then remove hold on SW1.**
Test Mode		X	X					**Simultaneously press and hold S1 and S7 for 3 sec.**
Demand Reset			X					**Momentarily press SW7 to initiate Demand Reset.**
Enter Menu					X			**To enter the menu mode and enter into submenus or select an option.**
Exit Menu						X		**To exit menu mode or to exit submenu into previous menu.**
Scroll Up Menu				X				**Scroll up the main menu or any submenu.**
Scroll Down Menu							X	**Scroll down the main menu or any submenu.**

5.01.2 Layout and description (Front View)



Connector	Description
J1	Short switch board meter option for optical port
J2	JTAG connector for ARM processor. Not Used
J4	JTAG connector for FPGA programming.
J5	Current and Voltage inputs from Transformers.
J6	Not Used
J7	JTAG connector for DSP. Not used
J8	Ethernet
J9	IRIG-B for GPS time stamp
J10	Connector for comm. Ports 1 thru 4 and Current Loop.
J13	Back Plane connector

J15	**Output relays**
J16	**Lithium Battery (Front Side)**
J17	**Lead-Acid Battery**

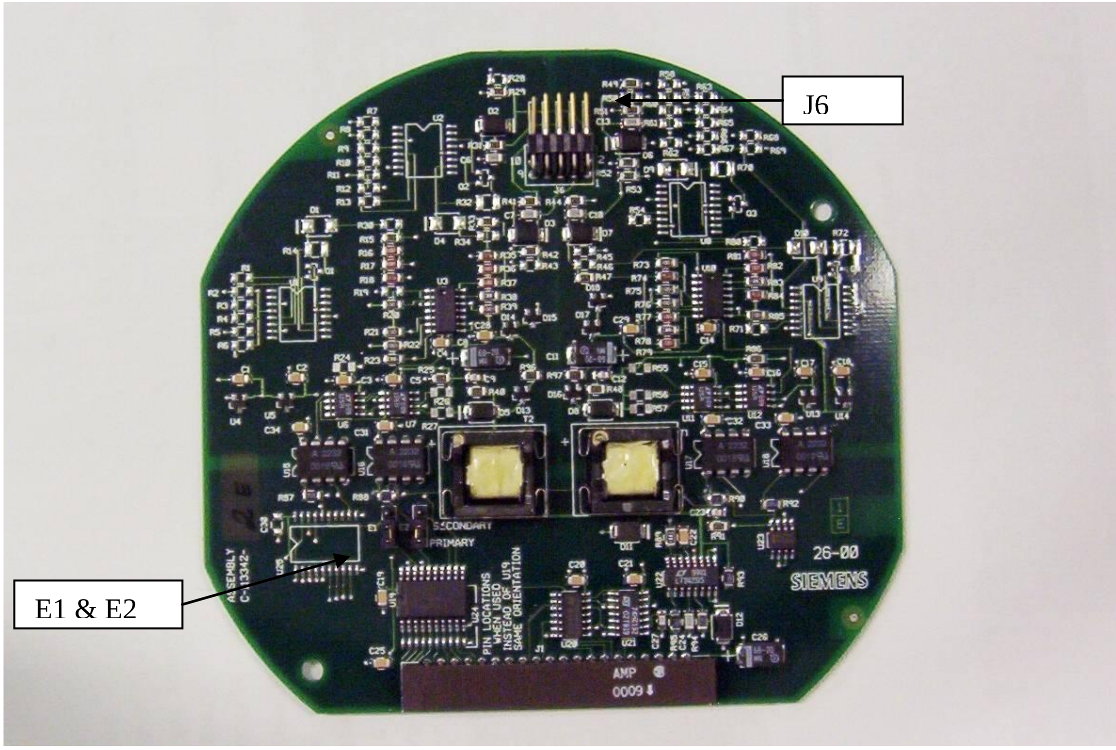
Jumpers

JP 1 – Communication port 2 usage select. Jumper between 1 and 2, the Communication Port is routed to the back plane for use on internal PCB cards (normally the old protocol cards). Jumper between pins 2 and 3, the comm. Port is routed out of the meter through cable J2.

J3 is a multi-function jumper set that is defined as follows:

J3-1, 2 No Format jumpers
J3- 3, 4 not used
J3- 5, 6 Watchdog disable
J3- 7, 8 BROM - Firmware programming.
J5- 9, 10 Not used

5.02 Analog Card (Option)
5.02.1 Layout and description (+/- 1 or 4 – 20ma Card)

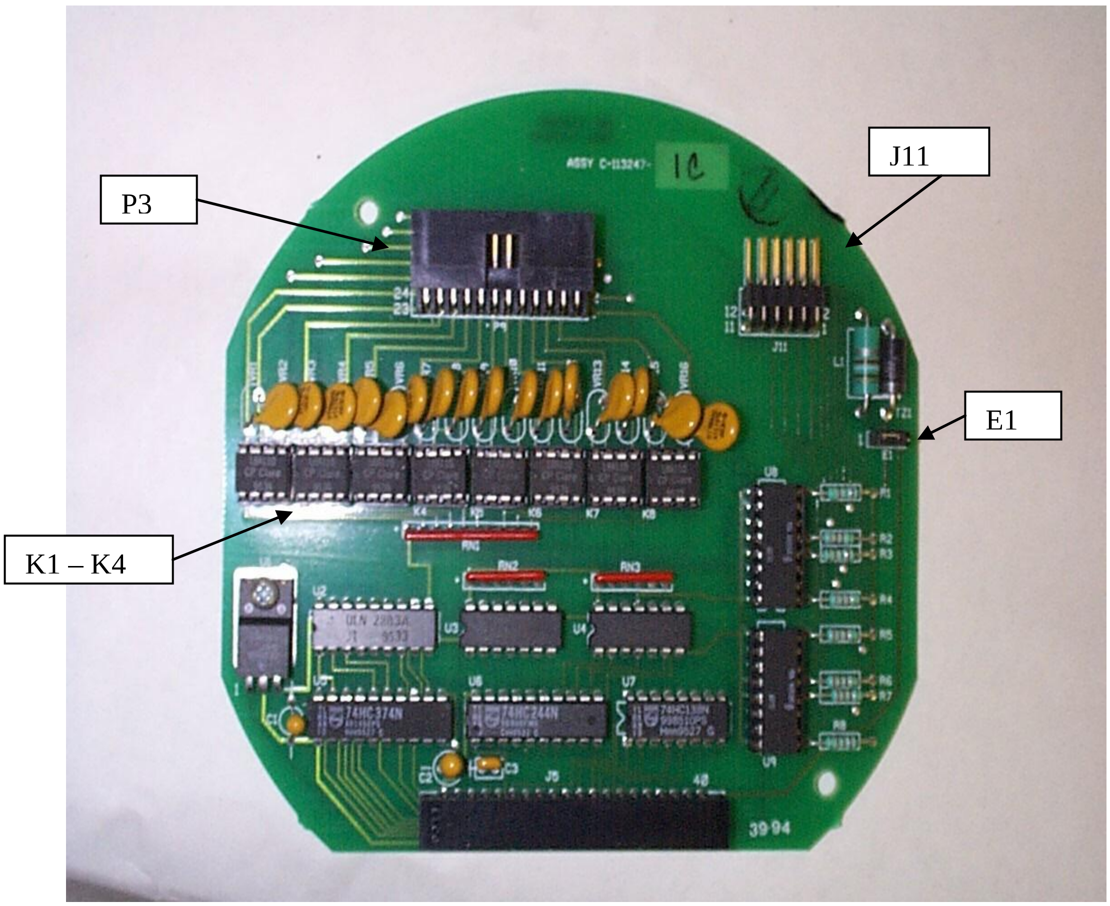


The connections and the programming are the same for both the +/-1ma card and the 4-20ma card.

Connector J6 has the four (4) outputs. They will be 1-4 on the primary card and 5-8 on the secondary card.

Jumpers E1 & E2 are used to set the card as primary or secondary.

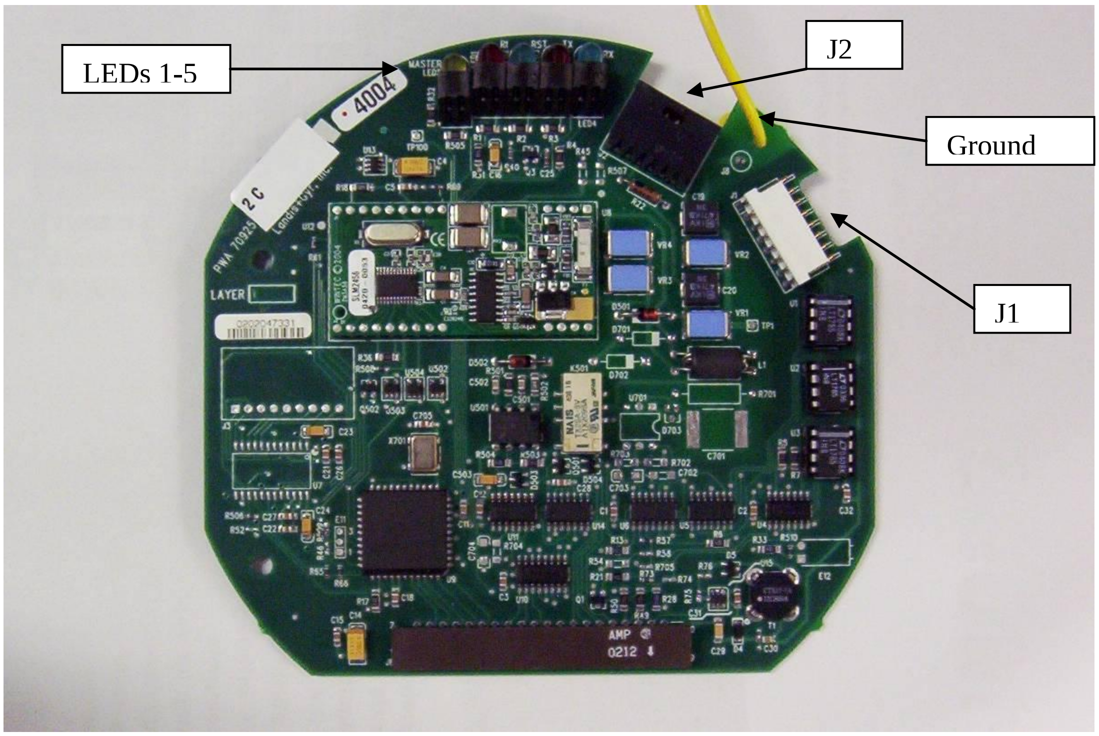
5.03 Input Output Card (Option)
5.03.1 Layout and description



The connector (Plug) P3 is for the 8 output relays and J11 is for the 8 pulse data or Status. Jumper E1 is used to select the method of powering the inputs. If the jumper is between 2 & 3 internal power from the meter is applied. When the jumper is set between 1 & 2 the inputs must be powered from an external power source. The optically isolated relays are K1-K8

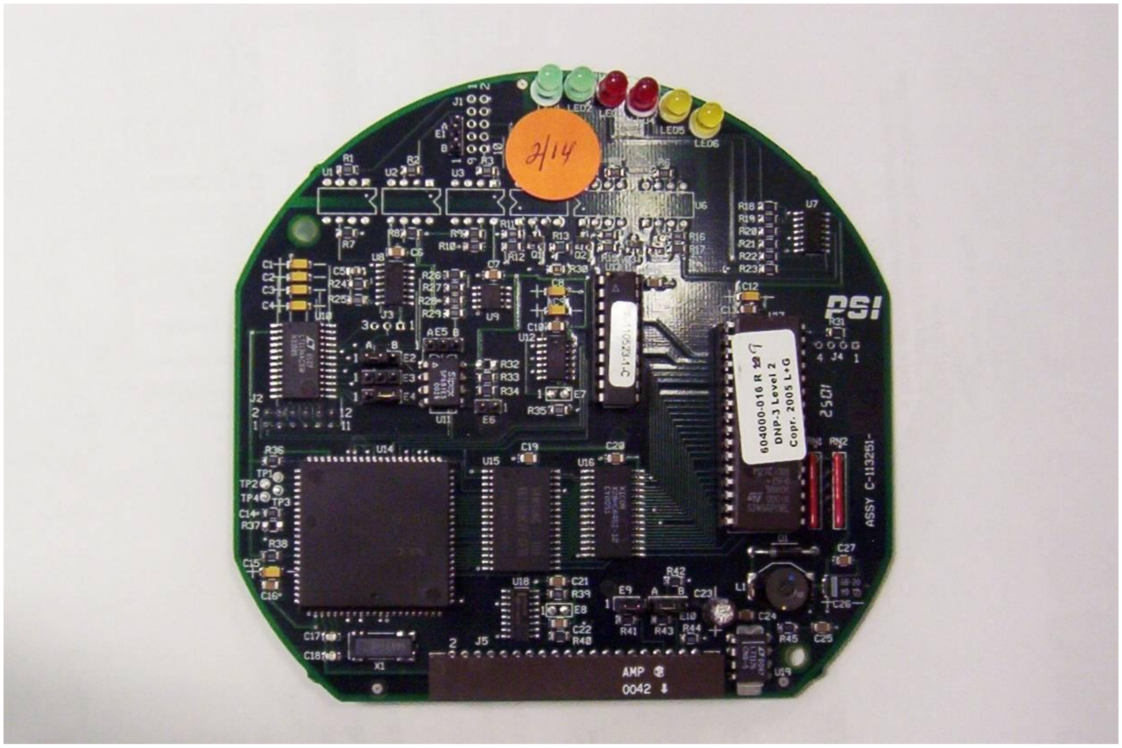
5.03 Modem Card (Option)

5.03.1 5.03.2 Layout and description (High Speed Modem)



The J1 connector is used to connect up to 31 meters together so they can share the phone line through the master modem. The J2 connector is for the phone cable. There are no user configurable jumpers on this card. There are 5 LED's for diagnostics. The yellow LED (5) is only used on the high speed modem to indicate if the modem is programmed as the master. Red LED (1) is the ring indicate. The green LED (2) is RST, red LED (3) transmit and green LED (4) is receive. The yellow wire is the ground connection.

5.04 Protocol Card (Option)



The protocol card is not required (or supported) to run DNP level 2 or modbus in the Elite Meter. However the meter does support the card for other protocols. The card has six (6) LEDs. The pair of green LEDs indicate communications between the card and the master. Green LED 1 will blink on requests from the master and LED 2 will blink on responses from the card. The two red LEDs indicate communications between the meter and the protocol card. The two yellow LEDs will blink error codes.

Port	Jumper	Position	Function
	E1	Not Used	On Standard Board
****	E1	A	Common Ground
****	E1	B	Isolated Ground
RS-232 (J2)	E2	A	RX data
RS-485 (J2)	E2	B	RX data
****	E2	B	Isolated RS232
	E3	*Not Used	Ring indicate
	E4	A	RS232 CTS used, signal from external source
	E4	B	RS232 CTS not used & RS485
	E5	Don’t Care	RS232
RS485	E5	A	RX data Recommended
****	E5	B	RX data Isolated RS232

E6	In	RS485 Terminated Not Recommended
E6	Out	RS485 Un-terminated Recommended
E7	N/A	Not customer configurable
E8	N/A	Not customer configurable

Meter Serial Port (connection from Protocol Board to CPU of meter):

Jumper	Position	Function
E9	In	TXD connected to backplane (standard)RS232-2
E9	Out	RXD connected to RS-232 external RS232-1
E10	A	RXD connected to backplane (standard)RS232-2
E10	B	RXD connected to RS-232 external RS232-1

6. Default Program

6.01.1 Default Demand Set-up
Demand Sub Interval 5 minutes
Number of Sub Intervals 6
Demand Interval 30 minutes
Demand Lockout 1 (Sub Intervals)
Power Fail Inhibit 0 (Sub Intervals)

6.01.2 Default Displays
All displays have 11 digits and 3 of the digits are to the right of the decimal. The decimal uses one of the eleven digits therefore you will have a value that looks like 10 digits. Example: 0123456.789

6.01.3 Customer Displays (Main) List
Delivered Kwh
Received Kwh
Delivered Kvarh
Received Kvarh
Power Factor
Max Delivered Kw
Data and Time of Max Delivered Kw
Max Received Kw
Data and Time of Max Received Kw
Max Delivered Kvar
Data and Time of Max Delivered Kvar
Max Received Kvar
Data and Time of Max Received Kvar
Power Factor @ Max. Kw Delivered
Power Factor @ Max. Kw Received
Current Date
Phase Indicator
Watt Direction
Compensated Delivered Kwh
Compensated Received Kwh
Compensated Delivered Kvarh
Compensated Received Kvarh
Compensated Power Factor
Max Compensated Delivered Kw
Data and Time of Max Compensated Delivered Kw
Max Compensated Received Kw
Data and Time of Max Compensated Received Kw
Max Compensated Delivered Kvar
Data and Time of Max Compensated Delivered Kvar
Max Compensated Received Kvar
Data and Time of Max Compensated Received Kvar
6.01.4 Utility Displays (Alternate) List

Inst. Phase A Volts
Inst. Phase B Volts
Inst. Phase C Volts
Inst. Phase A Amps
Inst. Phase B Amps
Inst. Phase C Amps
Inst. +/- Kw
Inst. +/- Kvar
Inst. Kva
Inst. Power Factor
Inst. Compensated +/- Kw
Inst. Compensated +/- Kvar
Inst. Compensated Kva
Inst. Compensated Power Factor
Inst. % Kwh with Losses
Inst. % Kvarh with Losses
Inst. THD Kw
Inst. THD Kvar
Inst. THD Phase A Volts
Inst. THD Phase A Amps
Inst. THD Phase N Amps
Data and Time of Last Reset
Previous Delivered Kwh
Previous Received Kwh
Previous Delivered Kvarh
Previous Received Kvarh
Previous Max Delivered Kw
Previous Data and Time of Max Delivered Kw
Previous Max Received Kw
Previous Data and Time of Max Received Kw
Previous Max Delivered Kvar
Previous Data and Time of Max Delivered Kvar
Previous Max Received Kvar
Previous Data and Time of Max Received Kvar
Previous Compensated Delivered Kwh
Previous Compensated Received Kwh
Previous Compensated Delivered Kvarh
Previous Compensated Received Kvarh
Previous Max Compensated Delivered Kw
Previous Data and Time of Max Compensated Delivered Kw
Previous Max Compensated Received Kw
Previous Data and Time of Max Compensated Received Kw
Previous Max Compensated Delivered Kvar
Previous Data and Time of Max Compensated Delivered Kvar
Previous Max Compensated Received Kvar
Previous Data and Time of Max Compensated Received Kvar

6.01.5 Test Displays List
Test Seconds
Test Received Kwh
Test Delivered Kvarh
Test Received Kvarh
Test Received Power Factor
Test Delivered Power Factor
Test Delivered Kwh
Test Max Delivered Kw
Test Max Received Kw
Test Max Delivered Kvar
Test Max Received Kvar
Test Compensated Received Kwh
Test Compensated Delivered Kvarh
Test Compensated Received Kvarh
Test Compensated Del.Power Factor
Test Compensated Delivered Kwh
Test Compensated Max Delivered Kw
Test Compensated Max Received Kw
Test Compensated Max Delivered Kvar
Test Compensated Max Received Kvar1
Test % Kwh with Losses
Test % Kvarh with Losses

6.01.6 Data Recorder (Main)
Recorder (1) 15 minute interval, 12 bit data

6.01.7 Data Recorder (Main) List

Channel 1 Kwh Delivered	Ke = 0.001
Channel 2 Kwh Received	Ke = 0.001
Channel 3 Kvarh Delivered	Ke = 0.001
Channel 4 Kvarh Received	Ke = 0.001
Channel 5 Compensated Kwh Delivered	Ke = 0.001
Channel 6 Compensated Kwh Received	Ke = 0.001
Channel 7 Compensated Kvarh Delivered	Ke = 0.001
Channel 8 Compensated Kvarh Received	Ke = 0.001

6.01.7 Data Recorder (2nd)
Recorder (2) 1 minute interval, 15 bit (16 bit signed data)

6.01.8 Data Recorder (2nd) List

Channel 1 V2h Phase A	Ke = 0.1
Channel 2 THD V2h Phase A	Ke = 0.001
Channel 3 I2h Phase A Phase	Ke = 0.01
Channel 4 THD I2h A Phase	Ke = 0.001
Channel 5 Kwh Phase A	Ke = 0.001
Channel 6 THD Kwh Phase A Delivered	Ke = 0.001

6.01.9 Output Relay Defaults

Relay 1	Kwh Delivered	Ke = 0.001	Dwell = 50ms
Relay 2	Kvarh Delivered	Ke = 0.001	Dwell = 50ms
Relay 3	Kvarh Received	Ke = 0.001	Dwell = 50ms
Relay 4	End Of Interval		Dwell = 1500ms

6.01.10 Analog Output Defaults

Analog 1	+/- Kw (-1.8 to 1.8)
Analog 2	+/- Kvar (-!.8 to 1.8)
Analog 3	Comp. +/- Kw (-1.8 to 1.8)
Analog 4	Comp. +/- Kvar (-!.8 to 1.8)
Analog 5	KVA (0-2.0)
Analog 6	PF (-1 - 1.0)
Analog 7	Comp. KVA (0-2.0)
Analog 8	Comp. PF (-1 - 1.0)

6.01.11 Auxiliary Input Defaults

Aux. 1	Kwh	Ke = 1.0	TR = 1.0
Aux. 2	Kvarh	Ke = 1.0	TR = 1.0
Aux. 3	Kwh	Ke = 1.0	TR = 1.0
Aux. 4	Kvarh	Ke = 1.0	TR = 1.0
Aux. 5	Kwh	Ke = 1.0	TR = 1.0
Aux. 6	Kvarh	Ke = 1.0	TR = 1.0
Aux. 7	Kwh	Ke = 1.0	TR = 1.0
Aux. 8	Kvarh	Ke = 1.0	TR = 1.0

6.01.12 DNP Set-up

RS232/485-4 DNP Baud Rate 9600

6.01.13 DNP Defaults

Binary Inputs: ON Status Inputs: ON Analog Data: 32 bits
Dead Band: 1.0% Counter Data: 32 bits
Event Data: Frozen Event Storage
Relay Outputs: None Unsolicited Response: Not Used
Collision Avoidance: Not Used Data Link: Not selected
Time out Resets: None Default Variations: Not changed
Pre Transmit Delay: 0ms Post Transmit Delay: 0ms
Time Sync Request: Never Freeze Minutes: 60

Data Point Configuration:
Point 0: Always Freeze event Circular, All Data Points, Counters
Class 0: Binary Inputs, Binary Outputs, Counters, Analogs

Register List	Scaled By
Inst. Phase A Volts	10
Inst. Phase B Volts	10
Inst. Phase C Volts	10
Inst. Phase A Amps	100
Inst. Phase B Amps	100
Inst. Phase C Amps	100
Inst. +/- Kw	10
Inst. +/- Kvar	10
Inst. Kva	10
Inst. Power Factor	100
Inst. Compensated +/- Kw	10
Inst. Compensated +/- Kvar	10
Inst. Compensated Kva	10
Inst. Compensated Pf	100
Delivered Kwh	1
Received Kwh	1
Delivered Kvarh	1
Received Kvarh	1
Compensated Delivered Kwh	1
Compensated Received Kwh	1
Compensated Delivered Kvarh	1
Compensated Received Kvarh	1

6.01.14 Modbus
RS232/485-3 Modbus   Baud Rate: 9600
Data Bits: 8   Start/Stop Bits: 1   Parity: Disabled
Slave Address: 1   CRC 1st Byte Low

6.01.15 Modbus Defaults

Register List	Scaled By
Inst. Phase A Volts	10
Inst. Phase B Volts	10
Inst. Phase C Volts	10
Inst. Phase A Amps	100
Inst. Phase B Amps	100
Inst. Phase C Amps	100
Inst. +/- Kw	10
Inst. +/- Kvar	10
Inst. Kva	10
Inst. Power Factor	100
Delivered Kwh	1
Received Kwh	1

Delivered Kvarh	1
Received Kvarh	1

6.01.16 Peer 2 Peer Communications
Current Loop Peer to Peer
Baud Rate 2400 (Default)

6.01.17 Peer 2 Peer Defaults
Peer Set-up:

Node Count	2
Peer ID	0
Min. Cycle	90
Status Outputs	None
Status Inputs	None
Time Sync.	Not Available

Numeric Outputs:

Buss	Line	Ke	QNeg	Field Type
T	1	0.000001		32 bit Numeric Demand
T	10	0.000001		32 bit Numeric Demand

Numeric Inputs:

Peer ID	Field Offset	Field type	Persistence
0	0	32 bit Numeric Demand	15
0	4	32 bit Numeric Demand	15
1	0	32 bit Numeric Demand	15
1	4	32 bit Numeric Demand	15

6.01.18 Power Quality Defaults (Single Level Sag & Swells)
Power Quality Mode: Extended
Level - 1 High 138, Low 102
Samples: 6 quarter cycles, Event: 120 quarter cycles

6.01.19.0 Advanved Power Quality Defaults (Multi-Level Sag & Swells)
Level - 1 High 132, Low 108
Samples: 1 quarter cycles, Event: 1800 quarter cycles
Level - 2 High 362, Low 96
Samples: 12 quarter cycles, Event: 1800 quarter cycles
Level - 3 High 362, Low 96
Samples: 1 quarter cycles, Event: 1800 quarter cycles

6.01.19.1 Nominal Voltage: set at 120.0 Volts
Used as a reference for some PQ analysis

6.01.19.2 Sag & Swell Analysis

Sag Analysis 1 Enabled (ITIC Requirements)

Set Point 0	0001 Cycles	Percent Deviation	70%
Set Point 1	0120 Cycles	Percent Deviation	80%
Set Point 2	2400 Cycles	Percent Deviation	90%

Set Points 3-9 Not used

Sag Analysis 2 Enabled (SEMI F47 Required)

Set Point 0	0048 Cycles	Percent Deviation	50%
Set Point 1	0120 Cycles	Percent Deviation	70%
Set Point 2	2400 Cycles	Percent Deviation	80%

Set Points 3-9 Not used

Sag Analysis 3 Enabled (SEMI F47 Recommended)

Set Point 0	0001 Cycles	Percent Deviation	01%
Set Point 1	2400 Cycles	Percent Deviation	80%

Set Points 2-9 Not used

Swell Analysis 1 Enabled (ITIC Requirements)

Set Point 0	0001 Cycles	Percent Deviation	120%
Set Point 1	0120 Cycles	Percent Deviation	110%

Set Points 2-9 Not used

Swell Analysis 2 Disabled

Swell Analysis 3 Disabled

6.01.19.3 Harmonic Evaluation Defaults
Sample Interval in seconds: 60
Evaluation Interval in seconds: 600
Counter for Total Evaluations: 10
Phase A, B and C voltage
Baseline voltage: 120.0
Max Harmonic: 40
THD Threshold: 8.0%
Individual Harmonic Thresholds: Percents set as per EN 5016

2nd	2.0%
3rd	5.0%
4th	1.0%
5th	6.0%
6th	0.5%
7th	5.0%
8th	0.5%

9th	1.5%
10th	0.5%
11th	3.5%
12th	0.5%
13th	3.0%
14th	0.5%
15th	0.5%
16th	0.5%
17th	2.0%
18th	0.5%
19th	1.5%
20th	0.5%
21st	0.5%
22nd	0.5%
23rd	1.5%
24th	0.5%

25th & above set at 50%

Phase A, B and C currents
Baseline current: 5.0
Max Harmonic: 40
TDD Threshold: 15.0%
Individual Harmonic Thresholds: Percents set as per IEE 519
For Distribution Systems 120V Through 69,000V (100<1000)

2nd	03.00%
3rd	12.00%
4th	03.00%
5th	12.00%
6th	03.00%
7th	12.00%
8th	03.00%
9th	12.00%
10th	03.00%
11th	05.50%
12th	01.37%
13th	05.50%
14th	01.37%
15th	05.50%
16th	01.37%
17th	05.00%
18th	01.25%
19th	05.00%
20th	01.25%
21st	05.00%
22nd	01.25%
23rd	02.00%

24th	00.50%
25th	02.00%
26th	00.50%
27th	02.00%
28th	00.50%
29th	02.00%
30th	00.50%
31st	02.00%
32nd	00.50%
33rd	02.00%
34th	00.50%
35th	01.00%
36th	00.25%
37th	01.00%
38th	00.25%
39th	01.00%
40th	00.25%

6.01.19.4 Current and Voltage Monitor Defaults

Voltage Monitor:

Intervals between monitorings in secs:	600	(10 Minutes)
Overvoltage Threshold:	5.00%	(6.0 Volts)
Undervoltage Threshold:	5.00%	(6.0 Volts)
Invalid voltage Threshold: (Below)	66.67%	(40.0 Volts)
History Interval in seconds:	604,800	(7 Days)

Voltage Distortion Monitor:

Intervals between monitorings in secs:	600	(10 Minutes)
Individual Harmonic Threshold:	3.00%	(3.6 Volts)
Total Harmonic Distortion Threshold:	5.00%	(6.0 Volts)
History Interval in seconds:	604,800	(7 Days)

Current Distortion Monitor:

Intervals between monitorings in secs:	600	(10 Minutes)
Individual Harmonic Threshold:	3.00%	(0.15 Amps)
Total Harmonic Distortion Threshold:	5.00%	(0.25 Amps)
History Interval in seconds:	604,800	(7 Days)

Violation Counter Defaults:

By Function:

Sag1	Counter	Capture	B. Reset
Totat Violations	40	N	N
Billing Period Violations	41	N	Y
Current Violations	42	N	N

Previous 1 Violations	43	N	N
Previous 2 Violations	44	N	N
Previous 3 Violations	45	N	N
Previous 4 Violations	46	N	N
Previous 5 Violations	47	N	N
Sag 2			
Totat Violations	20	N	N
Billing Period Violations	21	N	Y
Current Violations	22	N	N
Previous 1 Violations	23	N	N
Previous 2 Violations	24	N	N
Previous 3 Violations	25	N	N
Previous 4 Violations	26	N	N
Previous 5 Violations	27	N	N
Sag 3			Y
Totat Violations	30	N	N
Billing Period Violations	31	N	
Current Violations	32	N	N
Previous 1 Violations	33	N	N
Previous 2 Violations	34	N	N
Previous 3 Violations	35	N	N
Previous 4 Violations	36	N	N
Previous 5 Violations	37	N	N

Swell 1	Counter	Capture	B. Reset
Totat Violations	50	N	N
Billing Period Violations	51	N	Y
Current Violations	52	N	N
Previous 1 Violations	53	N	N
Previous 2 Violations	54	N	N
Previous 3 Violations	55	N	N
Previous 4 Violations	56	N	N
Previous 5 Violations	57	N	N
Swell 2			
Reserved Totat Violations	60	N	N
Billing Period Violations	61	N	Y
Current Violations	62	N	N
Previous 1 Violations	63	N	N
Previous 2 Violations	64	N	N
Previous 3 Violations	65	N	N
Previous 4 Violations	66	N	N
Previous 5 Violations	67	N	N
Swell 3			
Reserved Totat Violations	70	N	N
Billing Period Violations	71	N	Y
Current Violations	72	N	N
Previous 1 Violations	73	N	N
Previous 2 Violations	74	N	N

Previous 3 Violations	75	N	N
Previous 4 Violations	76	N	N
Previous 5 Violations	77	N	N

Voltage Monitor	Counter	Capture	B. Reset
Total Evaluations	100	N	N
Overvoltage Violations A Phase	101	N	N
Overvoltage Violations B Phase	102	N	N
Overvoltage Violations C Phase	103	N	N
Undervoltage Violations A Phase	104	N	N
Undervoltage Violations B Phase	105	N	N
Undervoltage Violations C Phase	106	N	N
Invaild voltage Violations A Phase	210	N	N
Invaild voltage Violations B Phase	211	N	N
Invaild voltage Violations C Phase	212	N	N
Consecutive Voltage Violations A Phase	213	N	N
Consecutive Voltage Violations B Phase	214	N	N
Consecutive Voltage Violations C Phase	215	N	N

Distortion Voltage Monitor	Counter	Capture	B. Reset
Total Evaluations	110	N	N
Individual Harmonic Violations A Phase	111	N	N
Individual Harmonic Violations B Phase	112	N	N
Individual Harmonic Violations C Phase	113	N	N
Total Harmonic Distortion Violations A Phase	114	N	N
Total Harmonic Distortion Violations B Phase	115	N	N
Total Harmonic Distortion Violations C Phase	116	N	N

Distortion Current Monitor	Counter	Capture	B. Reset
Total Evaluations	120	N	N
Individual Harmonic Violations A Phase	121	N	N
Individual Harmonic Violations B Phase	122	N	N
Individual Harmonic Violations C Phase	123	N	N
Total Harmonic Distortion Violations A Phase	124	N	N
Total Harmonic Distortion Violations B Phase	125	N	N
Total Harmonic Distortion Violations C Phase	126	N	N
Harmonic Evaluation Va	Counter	Capture	B. Reset
Total Evaluations	10	N	N
THD Violations	11	F/T	N
2nd - 63rd Harmonic	11	F/T	N

Reserved Va			
THD Violations	140	N	N
3rd,5th,7th,9th Harmonic	130	N	N
2nd,4th,6th,8th,10th Harmonic	131	N	N
11th,13th,15th Harmonic	132	N	N
12th,14th,16th Harmonic	133	N	N
17th,19th,21st Harmonic	134	N	N
18th,20th,22th Harmonic	135	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	136	N	N
24th,26th,28th,30th,32nd,34th Harmonic	137	N	N
35th,37th,39th Harmonic	138	N	N
36th,38th,40th Harmonic	139	N	N
41st-63rd Harmonic	11	F/T	N
Harmonic Evaluation Ia			
Total Evaluations	10	N	N
TDD Violations	173	E/T	Y
3rd,5th,7th,9th Harmonic	163	N	N
2nd,4th,6th,8th,10th Harmonic	164	N	N
11th,13th,15th Harmonic	165	N	N
12th,14th,16th Harmonic	166	N	N
17th,19th,21st Harmonic	167	N	N
18th,20th,22th Harmonic	168	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	169	N	N
24th,26th,28th,30th,32nd,34th Harmonic	170	N	N
35th,37th,39th Harmonic	171	N	N
36th,38th,40th Harmonic	172	N	N
41st-63rd Harmonic	14	F/T	N

Harmonic Evaluation Vb	Counter	Capture	B. Reset
Total Evaluations	10	N	N
THD Violations	12	F/T	N
2nd - 63rd Harmonic	12	F/T	N
Reserved Vb			
THD Violations	151	N	N
3rd,5th,7th,9th Harmonic	141	N	N
2nd,4th,6th,8th,10th Harmonic	142	N	N
11th,13th,15th Harmonic	143	N	N
12th,14th,16th Harmonic	144	N	N
17th,19th,21st Harmonic	145	N	N
18th,20th,22th Harmonic	146	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	147	N	N
24th,26th,28th,30th,32nd,34th Harmonic	148	N	N
35th,37th,39th Harmonic	149	N	N

36th,38th,40th Harmonic	150	N	N
41st-63rd Harmonic	12	F/T	N
Harmonic Evaluation Ib			
Total Evaluations	10	N	N
TDD Violations	184	E/T	Y
3rd,5th,7th,9th Harmonic	174	N	N
2nd,4th,6th,8th,10th Harmonic	175	N	N
11th,13th,15th Harmonic	176	N	N
12th,14th,16th Harmonic	177	N	N
17th,19th,21st Harmonic	178	N	N
18th,20th,22th Harmonic	179	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	180	N	N
24th,26th,28th,30th,32nd,34th Harmonic	181	N	N
35th,37th,39th Harmonic	182	N	N
36th,38th,40th Harmonic	183	N	N
41st-63rd Harmonic	15	F/T	N

Harmonic Evaluation Vc	Counter	Capture	B. Reset
Total Evaluations	10	N	N
THD Violations	13	F/T	N
2nd - 63rd Harmonic	13	F/T	N
Reserved Vc			
THD Violations	162	N	N
3rd,5th,7th,9th Harmonic	152	N	N
2nd,4th,6th,8th,10th Harmonic	153	N	N
11th,13th,15th Harmonic	154	N	N
12th,14th,16th Harmonic	155	N	N
17th,19th,21st Harmonic	156	N	N
18th,20th,22th Harmonic	157	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	158	N	N
24th,26th,28th,30th,32nd,34th Harmonic	159	N	N
35th,37th,39th Harmonic	160	N	N
36th,38th,40th Harmonic	161	N	N
41st-63rd Harmonic	13	F/T	N
Harmonic Evaluation Ic			
Total Evaluations	10	N	N
TDD Violations	195	E/T	Y
3rd,5th,7th,9th Harmonic	185	N	N
2nd,4th,6th,8th,10th Harmonic	186	N	N
11th,13th,15th Harmonic	187	N	N
12th,14th,16th Harmonic	188	N	N
17th,19th,21st Harmonic	189	N	N

18th,20th,22th Harmonic	190	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	191	N	N
24th,26th,28th,30th,32nd,34th Harmonic	192	N	N
35th,37th,39th Harmonic	193	N	N
36th,38th,40th Harmonic	194	N	N
41st-63rd Harmonic	16	F/T	N

Violation Counter Defaults:
By Number:

Not Used	Counter	Capture	B. Reset
Not Used	0	N	N
Not Used	1	N	N
Not Used	2	N	N
Not Used	3	N	N
Not Used	4	N	N
Not Used	5	N	N
Not Used	6	N	N
Not Used	7	N	N
Not Used	8	N	N
Not Used	9	N	N
Harmonic Evaluation Va	Counter	Capture	B. Reset
Total Evaluations	10	N	N
THD Violations	11	F/T	N
Harmonic Evaluation Vb	Counter	Capture	B. Reset
THD Violations	12	F/T	N
Harmonic Evaluation Vc	Counter	Capture	B. Reset
THD Violations	13	F/T	N
Harmonic Evaluation Ia			
41st-63rd Harmonic	14	F/T	N
Harmonic Evaluation Ib			
41st-63rd Harmonic	15	F/T	N
Harmonic Evaluation Ic			
41st-63rd Harmonic	16	F/T	N
Not Used	Counter	Capture	B. Reset
Not Used	17	N	N
Not Used	18	N	N
Not Used	19	N	N
Sag 2	Counter	Capture	B. Reset
Totat Violations	20	N	N
Billing Period Violations	21	N	Y
Current Violations	22	N	N
Previous 1 Violations	23	N	N
Previous 2 Violations	24	N	N
Previous 3 Violations	25	N	N
Previous 4 Violations	26	N	N
Previous 5 Violations	27	N	N
Not Used	Counter	Capture	B. Reset

Not Used	28	N	N
Not Used	29	N	N
Sag 3	Counter	Capture	B. Reset
Totat Violations	30	N	N
Billing Period Violations	31	N	Y
Current Violations	32	N	N
Previous 1 Violations	33	N	N
Previous 2 Violations	34	N	N
Previous 3 Violations	35	N	N
Previous 4 Violations	36	N	N
Previous 5 Violations	37	N	N
Not Used	Counter	Capture	B. Reset
Not Used	38	N	N
Not Used	39	N	N
Sag 1	Counter	Capture	B. Reset
Totat Violations	40	N	N
Billing Period Violations	41	N	Y
Current Violations	42	N	N
Previous 1 Violations	43	N	N
Previous 2 Violations	44	N	N
Previous 3 Violations	45	N	N
Previous 4 Violations	46	N	N
Previous 5 Violations	47	N	N
Not Used	Counter	Capture	B. Reset
Not Used	48	N	N
Not Used	49	N	N
Swell 1	Counter	Capture	B. Reset
Totat Violations	50	N	N
Billing Period Violations	51	N	Y
Current Violations	52	N	N
Previous 1 Violations	53	N	N
Previous 2 Violations	54	N	N
Previous 3 Violations	55	N	N
Previous 4 Violations	56	N	N
Previous 5 Violations	57	N	N
Not Used	Counter	Capture	B. Reset
Not Used	58	N	N
Not Used	59	N	N
Swell 2	Counter	Capture	B. Reset
Reserved Totat Violations	60	N	N
Billing Period Violations	61	N	Y
Current Violations	62	N	N
Previous 1 Violations	63	N	N
Previous 2 Violations	64	N	N
Previous 3 Violations	65	N	N
Previous 4 Violations	66	N	N
Previous 5 Violations	67	N	N
Not Used	Counter	Capture	B. Reset

Not Used	68	N	N
Not Used	69	N	N
Swell 3	Counter	Capture	B. Reset
Reserved Totat Violations	70	N	N
Billing Period Violations	71	N	Y
Current Violations	72	N	N
Previous 1 Violations	73	N	N
Previous 2 Violations	74	N	N
Previous 3 Violations	75	N	N
Previous 4 Violations	76	N	N
Previous 5 Violations	77	N	N
Not Used	Counter	Capture	B. Reset
Not Used	78	N	N
Not Used	79	N	N
Not Used	80	N	N
Not Used	81	N	N
Not Used	82	N	N
Not Used	83	N	N
Not Used	84	N	N
Not Used	85	N	N
Not Used	86	N	N
Not Used	87	N	N
Not Used	88	N	N
Not Used	89	N	N
Not Used	90	N	N
Not Used	91	N	N
Not Used	92	N	N
Not Used	93	N	N
Not Used	94	N	N
Not Used	95	N	N
Not Used	96	N	N
Not Used	97	N	N
Not Used	98	N	N
Not Used	99	N	N
Voltage Monitor	Counter	Capture	B. Reset
Total Evaluations	100	N	N
Overvoltage Violations A Phase	101	N	N
Overvoltage Violations B Phase	102	N	N
Overvoltage Violations C Phase	103	N	N
Undervoltage Violations A Phase	104	N	N
Undervoltage Violations B Phase	105	N	N
Undervoltage Violations C Phase	106	N	N
Not Used	Counter	Capture	B. Reset
Not Used	107	N	N
Not Used	108	N	N
Not Used	109	N	N
Distortion Voltage Monitor	Counter	Capture	B. Reset
Total Evaluations	110	N	N

Individual Harmonic Violations A Phase	111	N	N
Individual Harmonic Violations B Phase	112	N	N
Individual Harmonic Violations C Phase	113	N	N
Total Harmonic Distortion Violations A Phase	114	N	N
Total Harmonic Distortion Violations B Phase	115	N	N
Total Harmonic Distortion Violations C Phase	116	N	N
Not Used	Counter	Capture	B. Reset
Not Used	117	N	N
Not Used	118	N	N
Not Used	119	N	N
Total Evaluations	120	N	N
Individual Harmonic Violations A Phase	121	N	N
Individual Harmonic Violations B Phase	122	N	N
Individual Harmonic Violations C Phase	123	N	N
Total Harmonic Distortion Violations A Phase	124	N	N
Total Harmonic Distortion Violations B Phase	125	N	N
Total Harmonic Distortion Violations C Phase	126	N	N
Not Used	Counter	Capture	B. Reset
Not Used	127	N	N
Not Used	128	N	N
Not Used	129	N	N
Reserved Va	Counter	Capture	B. Reset
3rd,5th,7th,9th Harmonic	130	N	N
2nd,4th,6th,8th,10th Harmonic	131	N	N
11th,13th,15th Harmonic	132	N	N
12th,14th,16th Harmonic	133	N	N
17th,19th,21st Harmonic	134	N	N
18th,20th,22th Harmonic	135	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	136	N	N
24th,26th,28th,30th,32nd,34th Harmonic	137	N	N
35th,37th,39th Harmonic	138	N	N
36th,38th,40th Harmonic	139	N	N
THD Violations	140	N	N
Reserved Vb	Counter	Capture	B. Reset
3rd,5th,7th,9th Harmonic	141	N	N
2nd,4th,6th,8th,10th Harmonic	142	N	N
11th,13th,15th Harmonic	143	N	N
12th,14th,16th Harmonic	144	N	N

17th,19th,21st Harmonic	145	N	N
18th,20th,22th Harmonic	146	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	147	N	N
24th,26th,28th,30th,32nd,34th Harmonic	148	N	N
35th,37th,39th Harmonic	149	N	N
36th,38th,40th Harmonic	150	N	N
THD Violations	151	N	N
Reserved Vc	Counter	Capture	B. Reset
3rd,5th,7th,9th Harmonic	152	N	N
2nd,4th,6th,8th,10th Harmonic	153	N	N
11th,13th,15th Harmonic	154	N	N
12th,14th,16th Harmonic	155	N	N
17th,19th,21st Harmonic	156	N	N
18th,20th,22th Harmonic	157	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	158	N	N
24th,26th,28th,30th,32nd,34th Harmonic	159	N	N
35th,37th,39th Harmonic	160	N	N
36th,38th,40th Harmonic	161	N	N
THD Violations	162	N	N
Harmonic Evaluation Ia	Counter	Capture	B. Reset
3rd,5th,7th,9th Harmonic	163	N	N
2nd,4th,6th,8th,10th Harmonic	164	N	N
11th,13th,15th Harmonic	165	N	N
12th,14th,16th Harmonic	166	N	N
17th,19th,21st Harmonic	167	N	N
18th,20th,22th Harmonic	168	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	169	N	N
24th,26th,28th,30th,32nd,34th Harmonic	170	N	N
35th,37th,39th Harmonic	171	N	N
36th,38th,40th Harmonic	172	N	N
TDD Violations	173	E/T	Y
Harmonic Evaluation Ib	Counter	Capture	B. Reset
3rd,5th,7th,9th Harmonic	174	N	N
2nd,4th,6th,8th,10th Harmonic	175	N	N
11th,13th,15th Harmonic	176	N	N
12th,14th,16th Harmonic	177	N	N
17th,19th,21st Harmonic	178	N	N
18th,20th,22th Harmonic	179	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	180	N	N
24th,26th,28th,30th,32nd,34th Harmonic	181	N	N
35th,37th,39th Harmonic	182	N	N
36th,38th,40th Harmonic	183	N	N

TDD Violations	184	E/T	Y
Harmonic Evaluation Ic	Counter	Capture	B. Reset
3rd,5th,7th,9th Harmonic	185	N	N
2nd,4th,6th,8th,10th Harmonic	186	N	N
11th,13th,15th Harmonic	187	N	N
12th,14th,16th Harmonic	188	N	N
17th,19th,21st Harmonic	189	N	N
18th,20th,22th Harmonic	190	N	N
23rd,25th,27th,29th,31st,33rd Harmonic	191	N	N
24th,26th,28th,30th,32nd,34th Harmonic	192	N	N
35th,37th,39th Harmonic	193	N	N
36th,38th,40th Harmonic	194	N	N
TDD Violations	195	E/T	Y
Not Used	Counter	Capture	B. Reset
Not Used	196	N	N
Not Used	197	N	N
Not Used	198	N	N
Not Used	199	N	N
Not Used	200	N	N
Not Used	201	N	N
Not Used	202	N	N
Not Used	203	N	N
Not Used	204	N	N
Not Used	205	N	N
Not Used	206	N	N
Not Used	207	N	N
Not Used	208	N	N
Not Used	209	N	N
Voltage Monitor	Counter	Capture	B. Reset
Invaild voltage Violations A Phase	210	N	N
Invaild voltage Violations B Phase	211	N	N
Invaild voltage Violations C Phase	212	N	N
Consecutive Voltage Violations A Phase	213	N	N
Consecutive Voltage Violations B Phase	214	N	N
Consecutive Voltage Violations C Phase	215	N	N
Not Used	Counter	Capture	B. Reset
Not Used	216-252	N	N
Battery Seconds Billing Interval	253	N	Y
Total Battery Seconds	254	N	N

6.01.20 Waveform Capture
Waveform: Pre Trigger (10) Cycles Post Trigger (40) Cycles
Samples (16) Buffer (Circular)
RMS: Pre Trigger (20) Cycles Post Trigger (60) Cycles
Harmonics; Fixed at (2) Cycles
All trigger Event types turned on

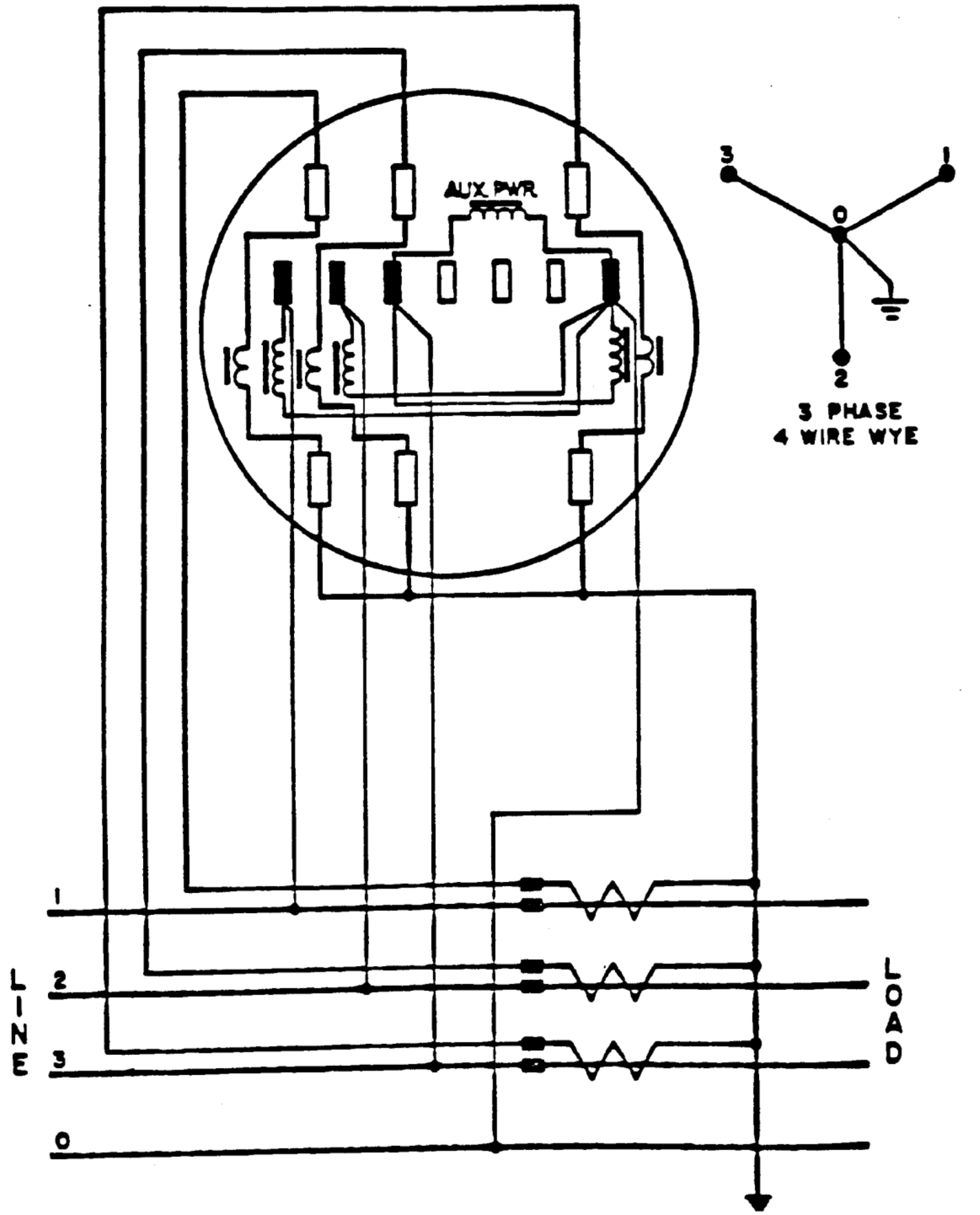
6.01.21 IRIG-B/Freeze Data
IRIG-B synchronization is enabled
IRIG-B synchronization interval count: 5
IRIG-B synchronization interval units in seconds
Min. difference between meter clock and IRIG-B for time adjustment 2 sec.
Min. difference between meter clock and IRIG-B for triggering an error 200 sec.

Freeze Every Specified Number of Minutes
Freeze every Minute

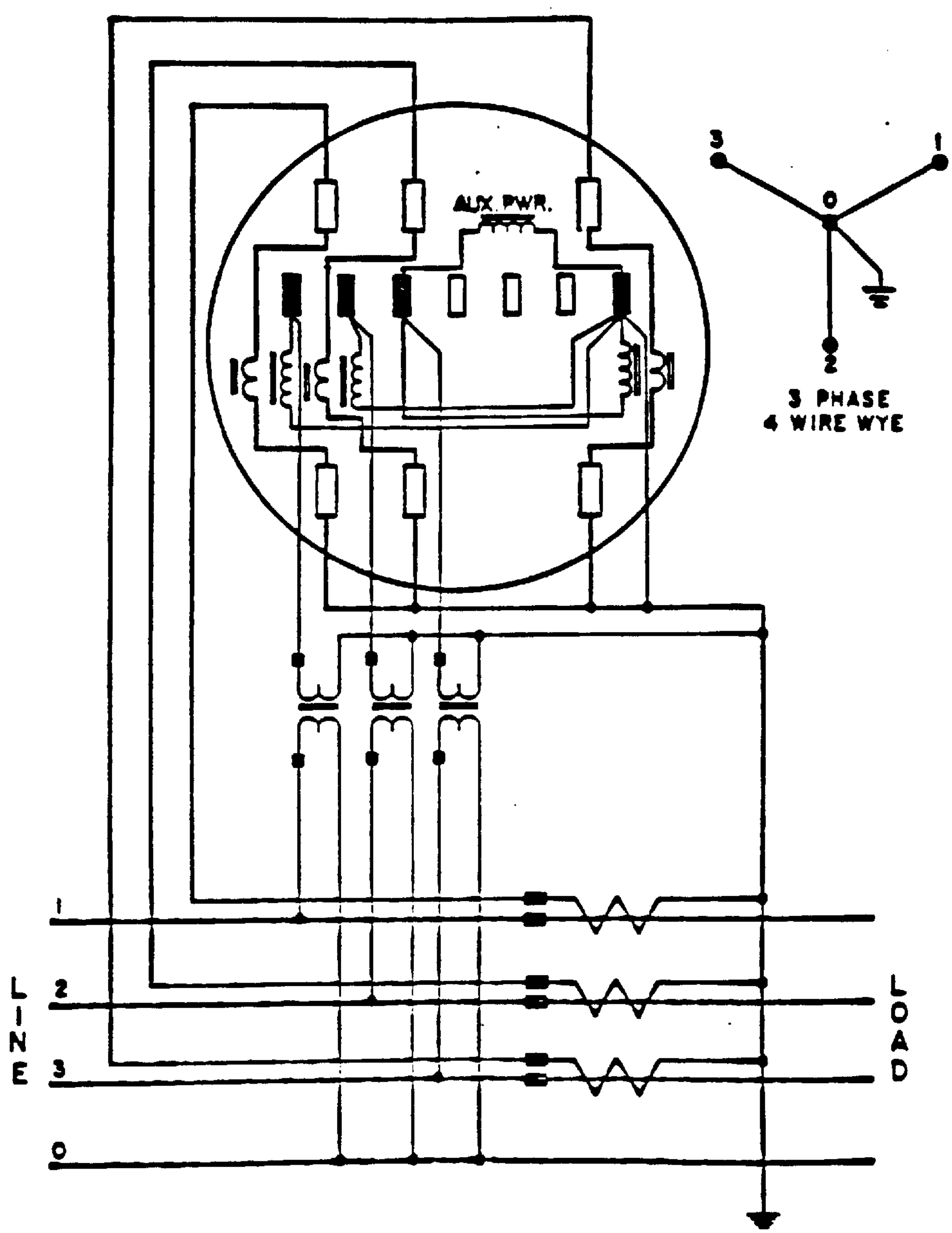
6.01.22 Power Transformer & Line Losses Defaults
All of the lose values are set at zero

7. Installation Meter Wiring Diagrams

7.01.1 3 Phase 4 wire Wye with Ct's and no Vt's

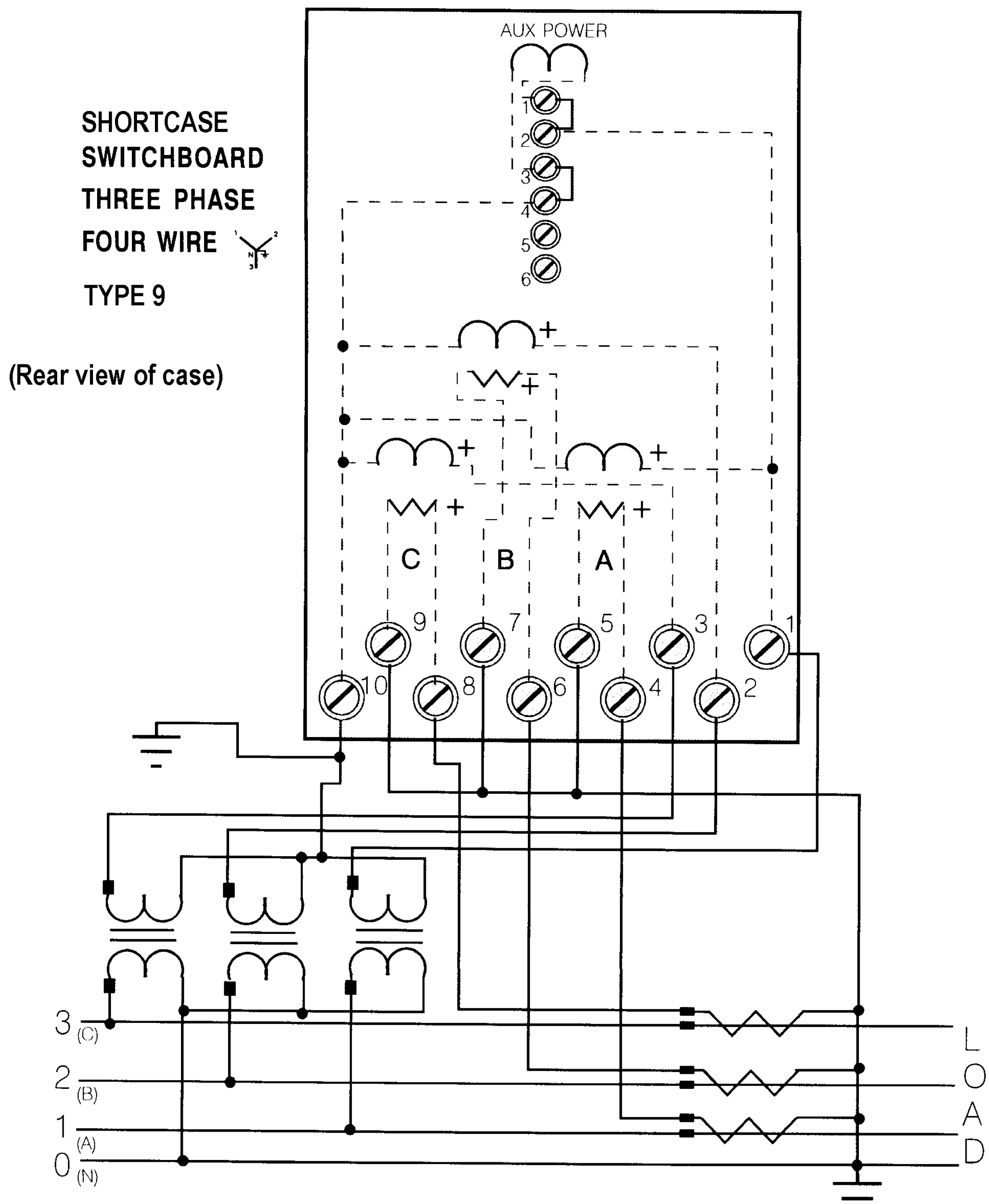


7.01.2 3 Phase 4 wire Wye with Ct's and Vt's



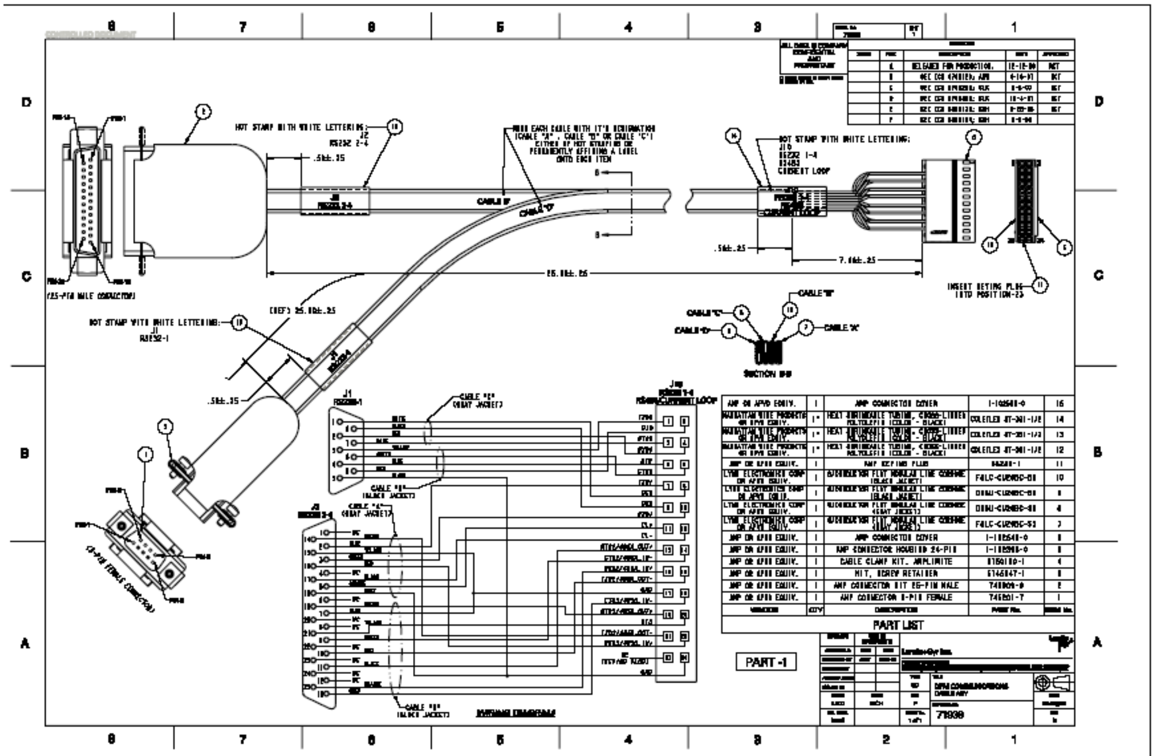
7.01.2 3 Phase 3 wire Delta

7.01.3 Three Element Short Switchboard



8. Cable & Pin-outs

8.01.1 Communications



RS232-1(J1) Note: Requires Null Modem when connecting to computer

DB 9 Pin-out

Pin 1	DCD	Pin 6	DSR
Pin 2	RX	Pin 7	RTS
Pin 3	TX	Pin 8	CTS
Pin 4	DTR	Pin 9	RIO
Pin 5	Gnd		

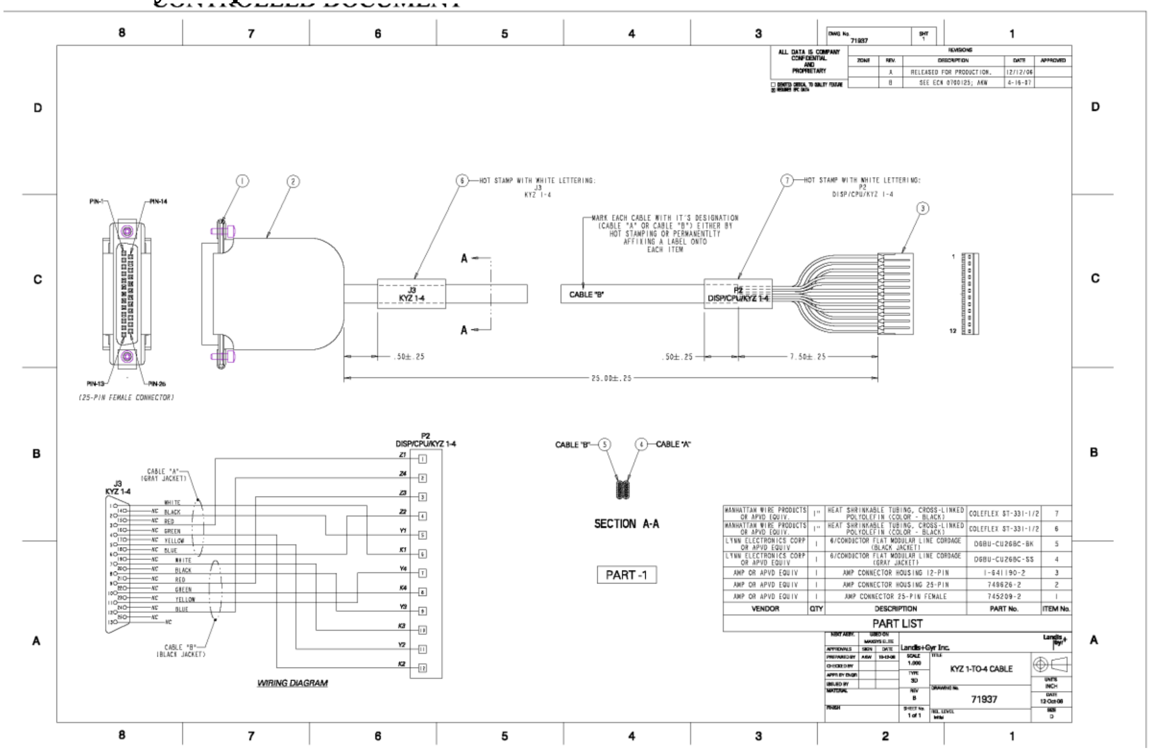
RS232-2,3,4 & RS485 (J2)

DB 25 Pin-out

Pin 1	NC	Pin 13	CTS RS232-4/485B_IN-
Pin 2	TX RS232-2	Pin 14	*TX RS232-4/485B_OUT-
Pin 3	RX RS232-2	Pin 15	Gnd
Pin 4	NC	Pin 16	RX RS232-4/485B_IN+
Pin 5	CL +	Pin 17	CL -
Pin 6	NC	Pin 18	Gnd
Pin 7	Gnd	Pin 19	*RTS RS232-4/485B_OUT+
Pin 8	NC	Pin 20	NC
Pin 9	CTS RS232-3/485A_IN-	Pin 21	R13
Pin 10	*TX RS232-3/485A_OUT-	Pin 22	NC
Pin 11	*RTS RS232-3/485A_OUT+	Pin 23	NC
Pin 12	NC	Pin 24	NC
Pin 25	RX RS232-3/485A_IN+		

* Used for RS485 (2-Wire)

8.01.2 Relay Outputs

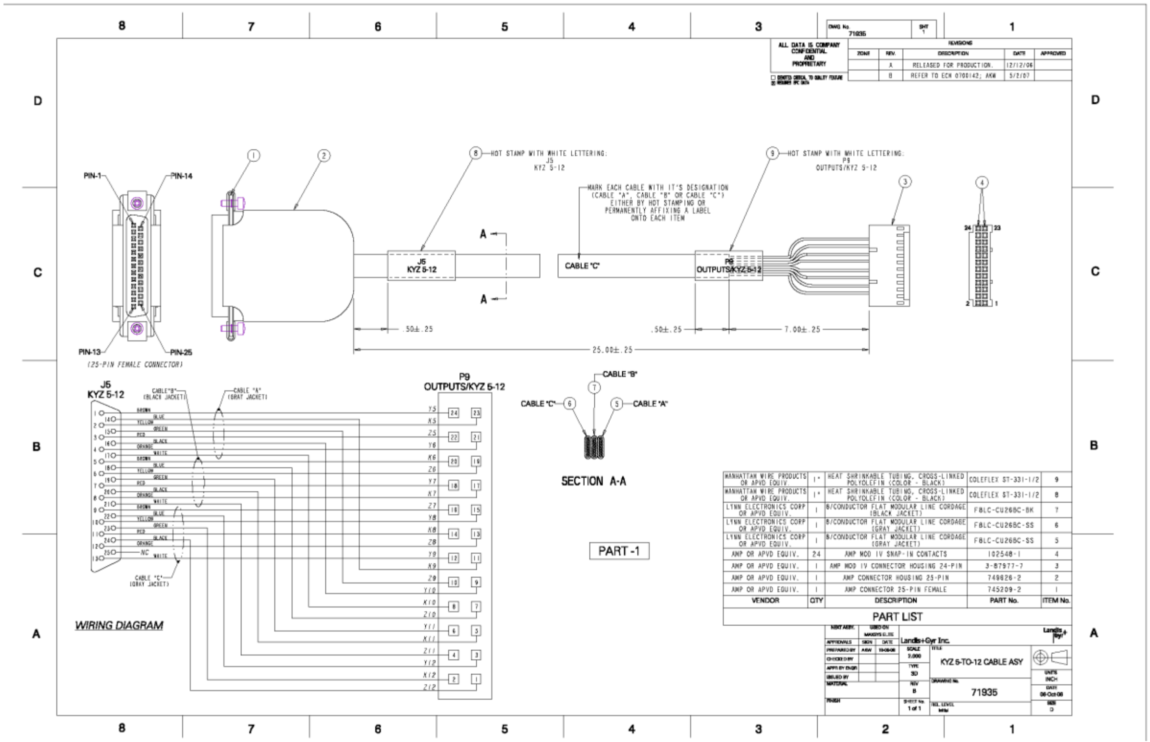


Outputs 1-4 (J3)

DB 25 Pin-out

Pin 1	K1	Pin 7	K3
Pin 2	Y1	Pin 8	Y3
Pin 3	Z1	Pin 9	Z3
Pin 4	K2	Pin 10	K4
Pin 5	Y2	Pin 11	Y4
Pin 6	Z2	Pin 12	Z4

Outputs 5-12 (J5)

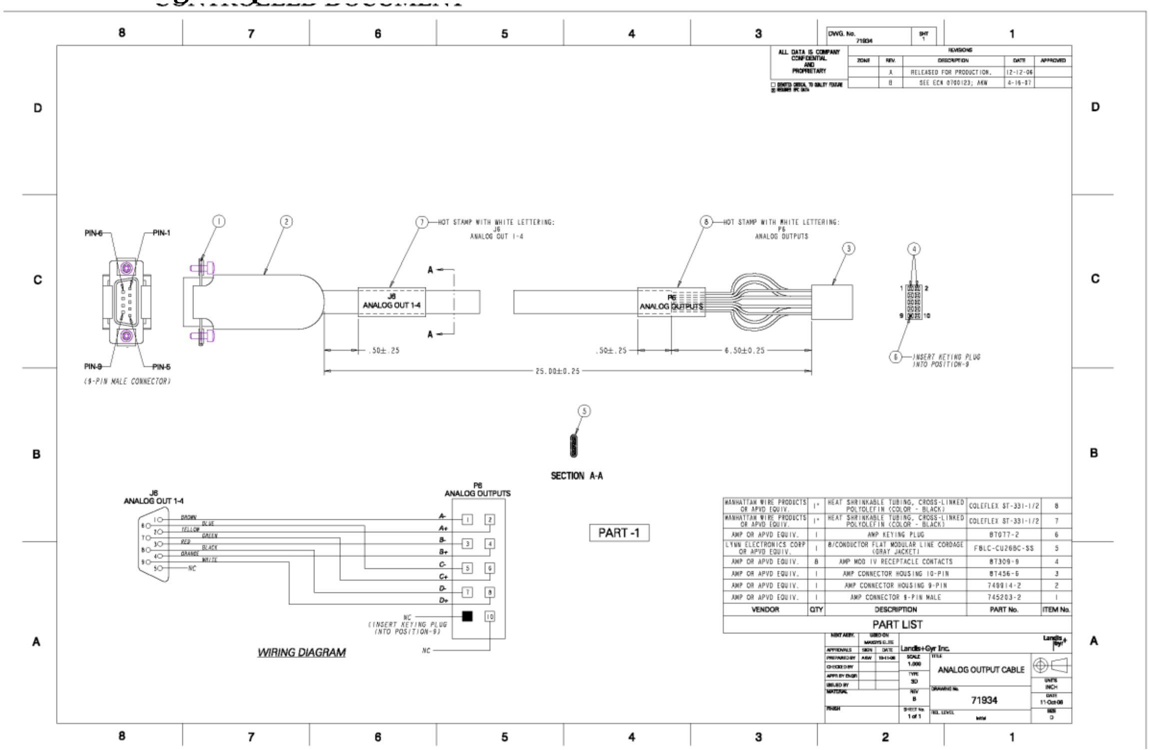


Outputs 5-12 (J5)

DB 25 Pin-out

Pin 1	Y5	Pin 13	Y9
Pin 2	K5	Pin 14	K9
Pin 3	Z5	Pin 15	Z9
Pin 4	Y6	Pin 16	Y10
Pin 5	K6	Pin 17	K10
Pin 6	Z6	Pin 18	Z10
Pin 7	Y7	Pin 19	Y11
Pin 8	K7	Pin 20	K11
Pin 9	Z7	Pin 21	Z11
Pin 10	Y8	Pin 22	Y12
Pin 11	K8	Pin 23	K12
Pin 12	Z8	Pin 24	Z12

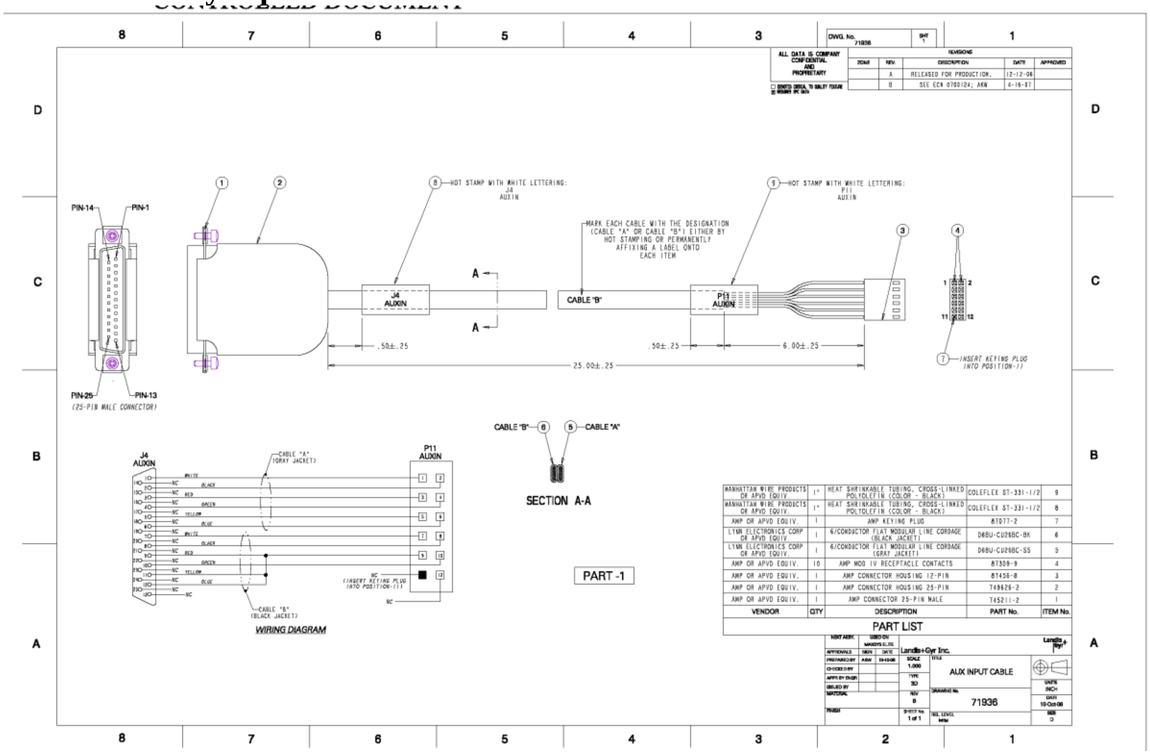
8.01.3 Analog Outputs



Outputs 1-4 (J8)

	DB 9 Pin-out		
Pin 1	-1(A)	Pin 7	+3(C)
Pin 2	+1(A)	Pin 8	-4(D)
Pin 3	-2(B)	Pin 9	+4(D)
Pin 4	+2(B)		
Pin 6	-3(C)		

8.01.4 Auxiliary Inputs



Inputs 1-8 (J4)

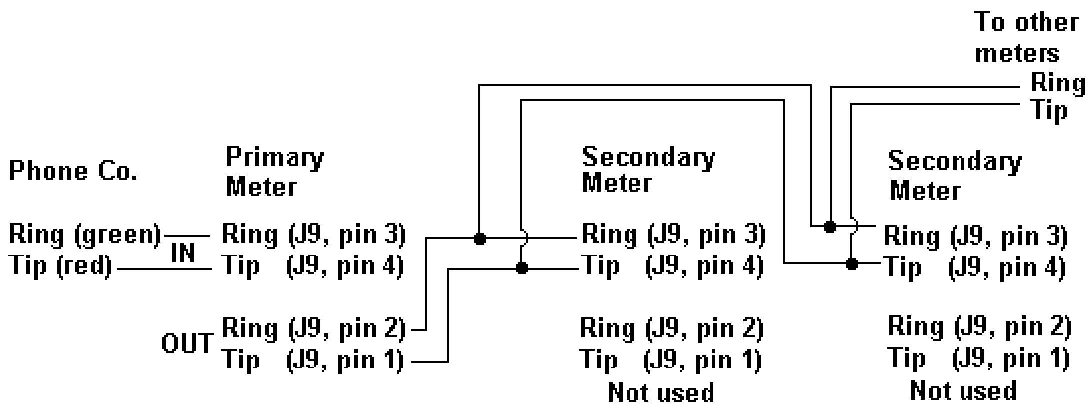
DB 25 Pin-out

Pin 1	1 In	Pin 7	7 In
Pin 2	2 In	Pin 8	8 In
Pin 3	3 In	Pin 9	Gnd
Pin 4	4 In	Pin 10	+V (auxiliary power)
Pin 5	5 In	Pin 11	Gnd
Pin 6	6 In	Pin 12	Gnd

8.01.6 Modems

1200 baud Modem

Connections for Daisy-Chain Operation - 1200 Baud:

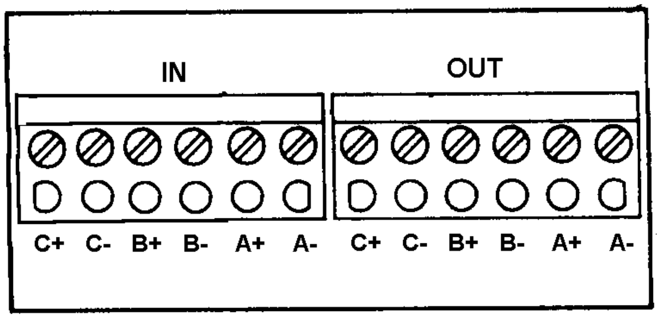


High Speed Modem

RS-485 Connections for High Speed Modem
Units equipped with the High Speed modem board must use an RS-485 serial bus for daisy-chain connection of the controller unit to down-line units. Two 6-pin connectors are present on the cable that is terminated with an RS485 interface board. Refer to the following figures for illustrations of the connectors. The RS-485 pin-outs on these connectors are as follows.

Terminal Strip 2 – Out		**Terminal Strip 1 – In**	
Controller to TS1 on First Down line Unit and all Up line Units to TS1 on next Down line Unit. Terminator strip on last Down line if needed.		**All Down line Units. Terminator strip on Controller if needed.**	
A-	**Xmit- to down line**	**A-**	**Rcv- from up line**
A+	**Xmit+ to down line**	**A+**	**Rcv+ from up line**
B-	**Rcv- from down line**	**B-**	**Xmit- to up line**
B+	**Rcv+ from down line**	**B+**	**Xmit+ to up line**
C-	**Ring- both units**	**C-**	**Ring- both units**
C+	**Ring+ both units**	**C+**	**Ring+ both units**

RS-485 Connections for High Speed Modem:



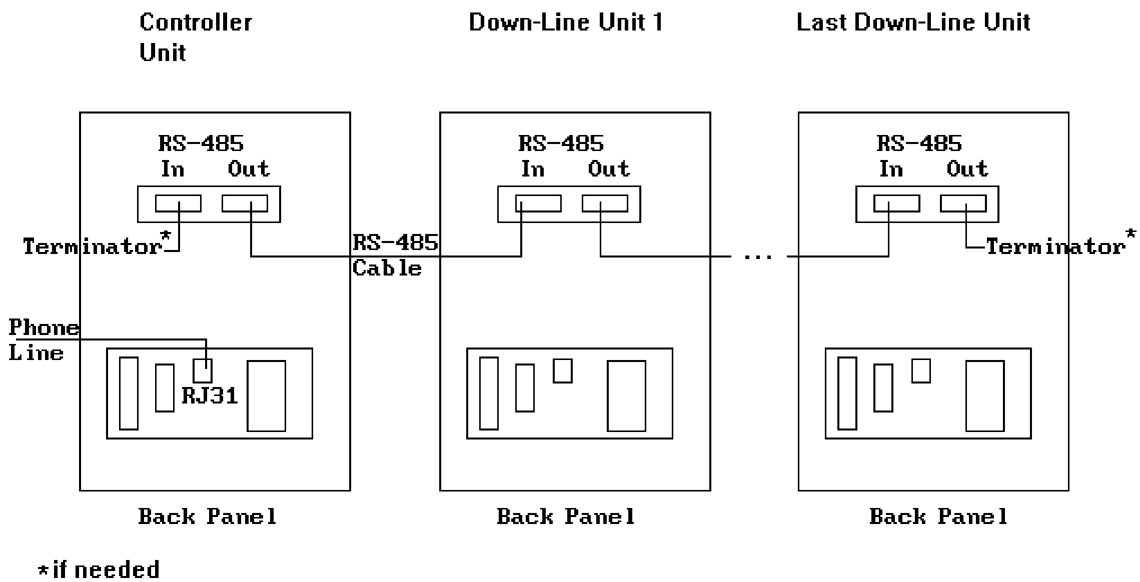
Note that:

1. The RJ11 or RJ31 will only be used on the modem card that is programmed as the master and will be the only meter that is connect to the phone line.

2. The dual 6-pin terminal strips for the RS-485 bus are located side-by-side. The left 6-pin terminal strip is for connection of the incoming RS-485 cable from the unit up line; the right 6-pin terminal strip is for connection of the outgoing RS-485 cable to the unit down line.

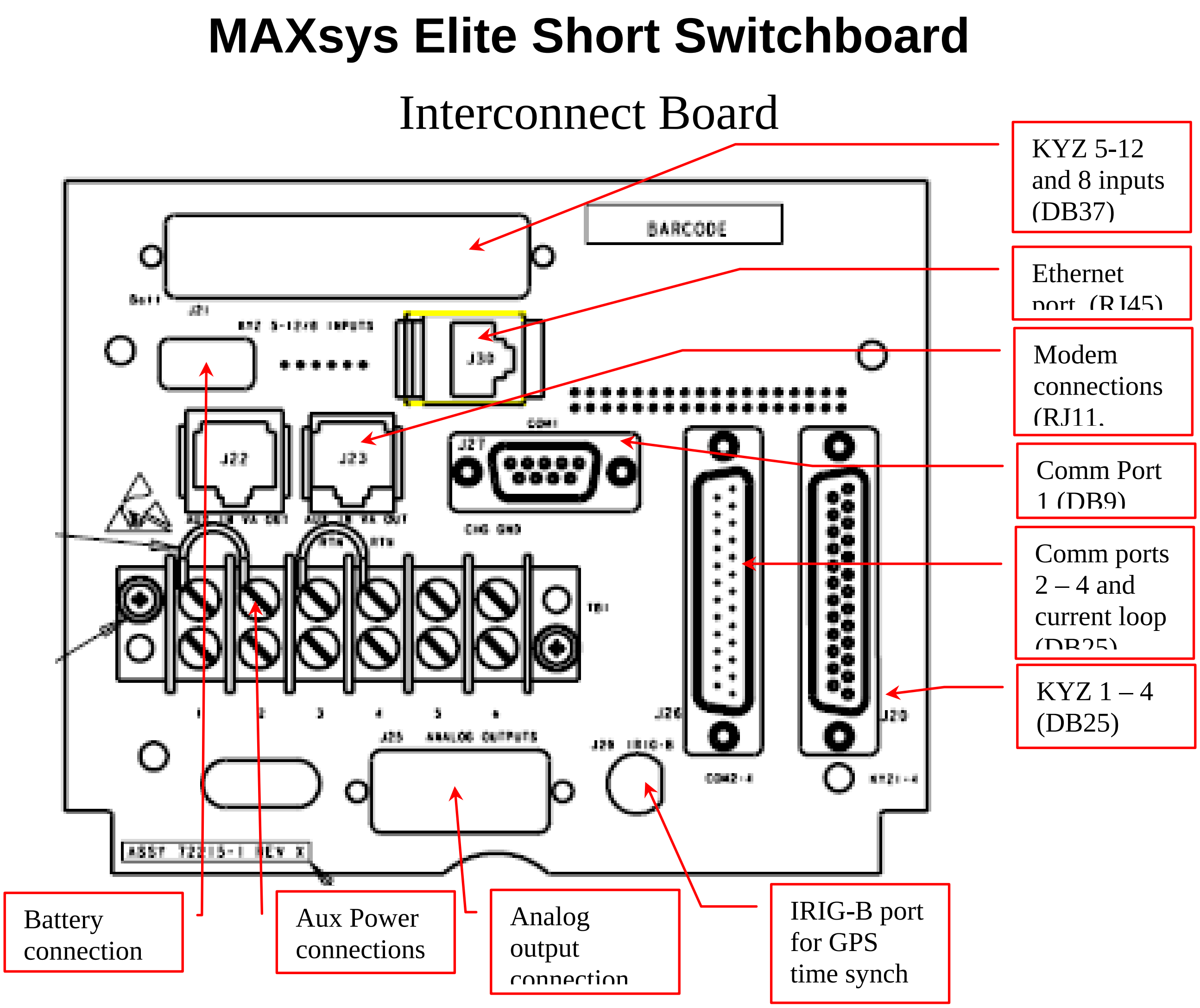
An RS-485 resistant terminator can be plugged into the left 6-pin terminal strip on the controlling unit and into the right 6-pin terminal strip on the last down-line unit only if excessive communication errors from down-line units occur. If system requirements show that the resistors are needed, contact service personnel.

Daisy-Chain with High Speed Modem in Socket base Meters are the same as the example below of switchboard case meters:



Multi-Drop with 2400 Baud Modems in Switchboard

8.01.7 Switchboard Meter Pin out



Pin-outs of DB Connectors

There are two DB25 connectors common to every short switchboard meter. The communication connector is labeled on the meter interconnect board as J26 and is a male DB25 connector. There is also a DB25 connector for the KYZ outputs 1 – 4 listed as J20 and connects to the main DPM board of the meter. In addition, there is a DB9 connector for comm port 1 listed as J27 on the interconnect board. The pin-out configurations for all of these connectors are as follows:

J26 Communication ports 2 – 4 and current loop (DB25) pin-out

Pin	Use
1	N/C
2	TXD1
3	RXD1
4	N/C
5	CL+
6	N/C
7	GND_DB25_M1
8	N/C
9	CTS2/485A_IN- Port 3
10	*TXD2/485A_OUT- Port 3
11	*RTS2/485A_OUT+ Port 3
12	N/C
13	CTS3/485B_IN- Port 4
14	*TXD3/485B_OUT- Port 4
15	GND_DB25_M1
16	RXD3/485B_IN+ Port 4
17	CL-
18	GND_DB25_M
19	*RTS3/485B_OUT+ Port 4
20	N/C
21	RI3
22	N/C
23	N/C
24	N/C
25	RXD2/485A_IN+ Port 3

* Used for RS485 (2-Wire)

J20 KYZ 1 – 4 (DB25) pin-out

Pin	Use
1	K1
2	Y1
3	Z1
4	K2
5	Y2
6	Z2
7	K3
8	Y3
9	Z3
10	K4
11	Y4
12	Z4
13	N/C
14	N/C
15	N/C
16	N/C
17	N/C
18	N/C
19	N/C
20	N/C
21	N/C
22	N/C
23	N/C
24	N/C
25	N/C

J27 Communication port 1 (DB9)pin-out

Pin	Use
1	DCD
2	RX
3	TX
4	DTR
5	GND_DB25_M
6	GND_DB9
7	RTS
8	CTS
9	RI

There are also optional features that can be terminated to the interconnect board. These features include analog outputs (DB15) and (8) additional KYZ outputs and (8) inputs on a DB37. The pin-outs for each of these options are as follows:

Pin-outs of DB-15 Connector on Termination Board for Four Analog Outputs

Pin	Use	
1	A-	Analog output 1
2	A+	Analog output 1
3	B-	Analog output 2
4	B+	Analog output 2
5	C-	Analog output 3
6	C+	Analog output 3
7	D-	Analog output 4
8	D+	Analog output 4
9	Not used	
10	Not used	
11	Not used	
12	Not used	
13	Not used	
14	Not used	
15	Not used	

Pin-outs of Optional DB-37 Connector on Termination Board for Eight Relay Outputs and Eight Auxiliary Inputs if Unit Equipped with Input/Output Board

Pin	Use
1	GND
2	+VW
3	Not used
4	Y5
5	K5
6	Z5
7	Y6
8	K6
9	Z6
10	Y7
11	K7
12	Z7
13	Y8
14	K8
15	Z8
16	NOT USED
17	NOT USED
18	Input 1
19	Input 2
20	Input 3
21	Input 4
22	Y9
23	K9
24	Z9
25	Y10
26	K10
27	Z10
28	Y11
29	K11
30	Z11
31	Y12
32	K12
33	Z12
34	Input 5
35	Input 6
36	Input 7
37	Input 8

9. Testing

9.01.1

The accuracy testing for the Elite meter is done through the transmit “LED” of the optical port on the face of the meter. The optical port is located on the lower left hand side of the meter face and the left “LED” is the transmit LED and is located on the left side of the port. The LED has 9 modes of operation. Optical communications (type 7 protocol), Watt hour, Var hour, Compensated Watt hours Comp. 1, Compensated Var hours Comp. 1, Compensated Watt hours Comp. 2, Compensated Var hours Comp. 2, Compensated Watt hours Comp. 3 and Compensated Var hours Comp. 3. The modes can be changed using MAXcom under the test mode screen. The meter does not need to be put into test mode to change the LED modes. The mode of operation can be seen on the meter display using the menu system. The user would enter the menu system using the buttons (E) on the face of the meter. They would then select “communications” from the list of menu items. This will take the user to a sub menu where they can select the optical port. To select the optical port the user will select the “more ports” option that will bring up another menu with “optical port”. After selecting “optical port” the screen will display the “Cal Pulse” mode. At the bottom of the meter display there will also be a box around the LED icon that is being output by the LED.

When testing for meter accuracy it is recommended that no test should be run for less than 30 seconds. The 30 second test is recommended to reduce timing errors between the test equipment and the meter. The following examples are for a Form9S, 120 volt meter with a Kh of 1.0 being tested a rated voltage and a test current of 2.5 and 0.25 amps.

Full Load	10 Rev.	40 seconds
Power Factor	05 Rev.	40 seconds
Light Load	02 Rev.	80 seconds

When testing TLC accuracy the values meter is normally tested at the rated secondary value of the instrument transformer.
The following examples are for a Form 9S, 120 volt meter with a Kh of 1.0 that is connect to instrument transformers, VTR=7200:120 and CTR=1200:5. The tests are normally run at rate voltage (120 volts) and a test current of % and 0.5 amps.

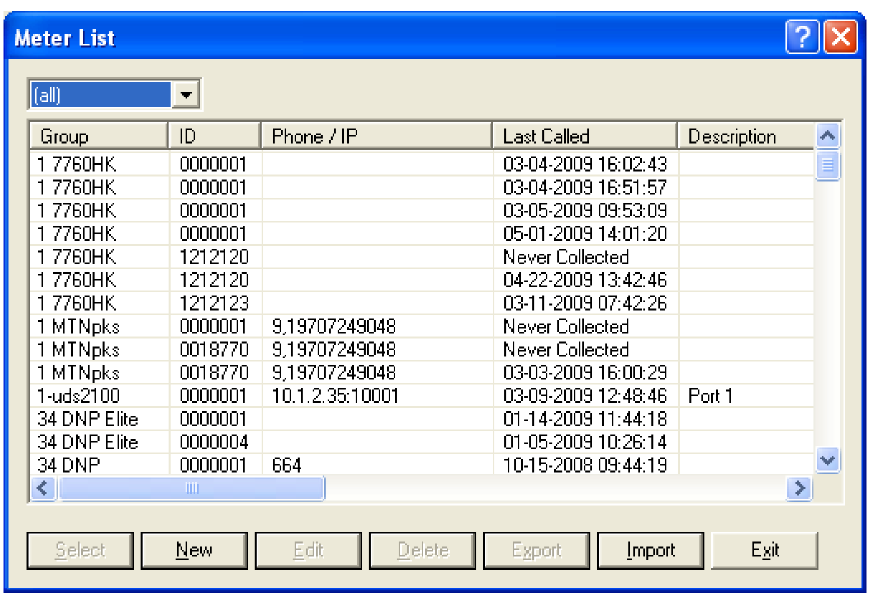
Full Load	20 Rev.	40 seconds
Power Factor	10 Rev.	40 seconds
Light Load	04 Rev.	80 seconds

TEST MODE

When the meter is placed into test mode the meter will stop incrementing all of the register this includes Energy, demand and instantaneous values. The output relays will be turned off and the data recorder will not record data while the meter is in test mode. Only values from table 36 (test display) will be active. If the user includes any of the normal display items coming from table 3 (instantaneous/last demand values) and table 15 (energy and Max demands) the readings will be the values that the meter was reading at the time the meter was placed in test mode. There are two (2) ways to put the meter into test mode. The first (preferred) is to use the MAXcom software this will prevent you from accidently doing a demand reset. If possible us a communications port other than the optical for the MAXcom connection. If you use the optical port communication you will need to disconnect the the optical probe from the port when you need to use the pulse coming from the LED. You do not need to stop and restart MAXcom, just reconnect the probe. The other method is to remove the cover and press and simultaneously hold the S1 Mode Select button on the lower left side of the DPM (display card) and then press and hold the demand reset button until the meter goes into test mode (Do Not press the demand reset first).
Method 1

Using Maxcom Software:

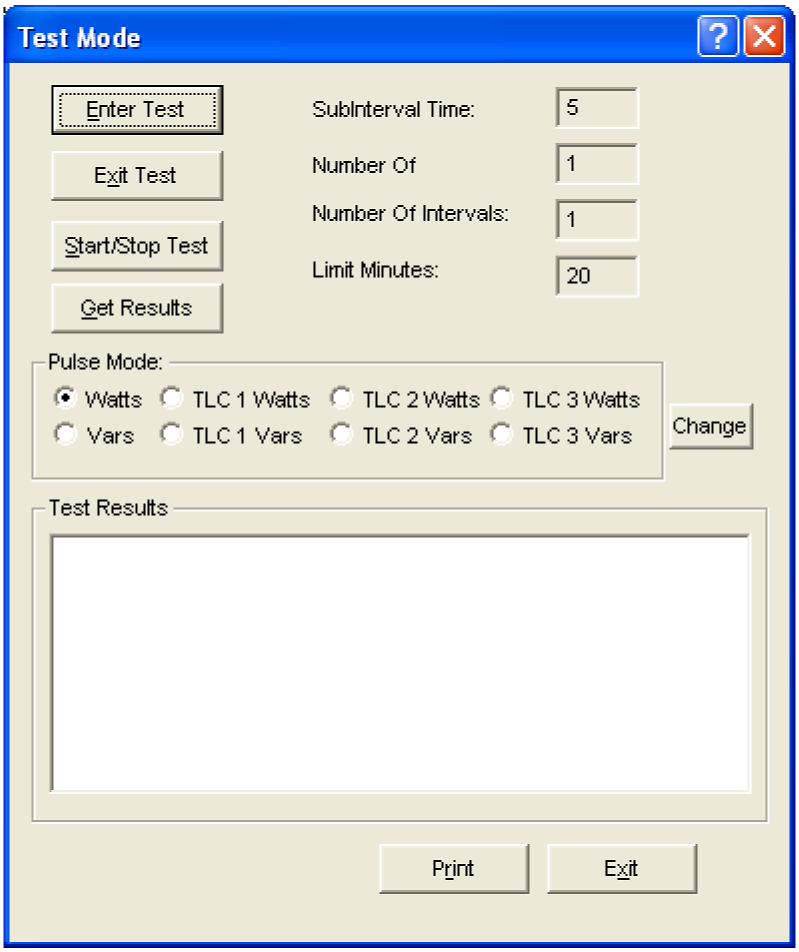
1. Start-up the MAXcom software.
2. Switch to the "Data Collection Mode" within MAXcom.
3. Open the unit manager and select the meter from the meter list. If the meter is not in the list you will need to make new file.



4. Connect your computer to the meter using one of the communications ports.
5. Select the "connect to meter" ICON.

6. After MAXcom connects to the meter the "Enter/Exit Test Mode" ICON will be enabled.
7. Click the Enter/Exit Test Mode ICON.

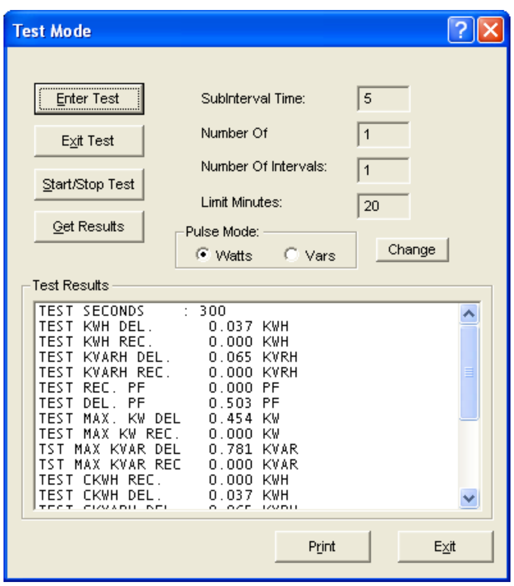
Test Mode Screen



8. The test "Subinterval Time" (length of demand subinterval), "Number OF Subintervals (number of subintervals per demand interval)", "Number Of Intervals" (number of demand interval for test to run) and "Limit Minutes" (the amount of time the meter will remain in test mode without activity) the entrees should not be changed after the meter has been programmed.
9. Pulse Mode will allow you to select which of the unit of measures will be on the calibration LED. The pulse mode can be changed without putting the meter into test mode. The meter will remain in the last mode which was selected.
10. Have the meter out of service or take the meter out of service if you are not using the customer's load for the test.

11. Click "Enter Test" to put the meter into test mode. Note: this will stop the meter from up-dating the active (billing) registers.
    a. The display on the meter will indicate the meter has entered into test mode. Click "Start Test" in the software.
12. Set-up the test equipment and apply the test load.
13. Click "Start Test"
    a. The test mode displays will appear on the face meter. If the test seconds is at the top of the list it can be seen counting up. Note: There will be no demand values until the test has completed or the test has been stopped by clicking "Stop Test". WARNING the test must end or be stoped before you try and exit test mode or change LED modes.
14. An alternate method for starting the test would be to power the meter down and the power the meter up. On power-up the meter will start the test. This method was provide so a number of meters (gang testing) could start there test at the same time. NOTE turning the power off to the meter will not take the meter out of test mode.
15. When the test has been completed or stopped. The meter display will show "Test Mode Complete". And you can read the results from the meter display or retrieve the results using MAXcom.

16. Click "Get Results



17. You can run another test be clicking "Start Test".
    a. This will clear the old test data and the test will start.
18. When you have completed your testing.
    a. Remove the testing equipment.

19. Take the meter out of test mode by clicking “Exit” (The meter cannot be running a test when you try and exit test mode), always stop the test before exiting the test mode.
20. Place the meter back into service.

Method 2

Using the buttons on the meter face:

1. Remove the meter from service.
2. Remove (break) the meter seal.\
3. Remove the meter cover.
4. To put the meter into test mode. The user will simultaneously press and hold the S1 Mode Select button on the lower left side of the DPM (display card) and then press and hold the demand reset button until the meter goes into test mode (Do Not press the demand reset first).
5. This will put the meter into test mode. Note: This will stop the meter from up-dating the active (billing) registers.
   a. The display on the meter will indicate the meter has entered into test mode. Click “Start Test” in the software.
6. Set-up the test equipment and apply the test load.
7. Press the demand reset button on the face of the meter to start the test.
   a. The test mode displays will appear on the face meter. If the test seconds is at the top of the list it can be seen counting up. Note: There will be no demand values until the test has completed or the test has been stopped by clicking “Stop Test”.
8. The LED test mode should be changed using MAXcom, this will keep you from needing to leave test mode.
9. An alternate method for starting the test would be to power the meter down and the power the meter up. On power-up the meter will start the test. This method was provide so a number of meters (gang testing) could start there test at the same time.
10. When the test has been completed or stopped. The meter display will show “Test Mode Complete”. And you can read the results from the meter display by scrolling the list using the buttons on the face of the meter.
11. You can run another test be pressing the demand reset.
    a. This will clear the old test data and the test will start.
12. When you have completed your testing.
    a. Remove the testing equipment.
13. Take the meter out of test mode by simultaneously press and hold the S1 Mode Select button on the lower left side of the DPM (display card) and then press and hold the demand reset button until the meter comes out of test mode. The meter cannot be running a test when you try and exit test mode, always stop the test before exiting the test mode.
14. Place the meter back into service.

10. Specifications

10.01.1 Meter Accuracy

10.01.2 Time Base Accuracy

When synchronized to the 60Hz line frequency, the time base accuracy is equal to the line frequency accuracy. If the accuracy of the line frequency falls above or below 0.1Hz, then timing will automatically switch to crystal timing. For installations where line frequency is not stable, the meter timing will be taken from a crystal on the measurement/CPU board. The crystal accuracy requirement is +/- 1 minute per year at 25C, and +/-4 minutes per year over the range of -40 to +85 degrees C.

10.01.3 Output Relays

Output Relay Specifications

open circuit voltage	closed circuit current	maximum VA Switching
200VDC or 200VAC	100 ma	14 VA AC & 20 VA DC

Wire Size Range: 12-22 AWG

10.01.4 Auxiliary Inputs

Auxiliary Input Specifications

Type	Form	Maximum response time	Voltage Source	Circuit Current
2 wire	A	12 transitions / second	12 - 15VDC	8 ma

Wire Size Range: 12-22 AWG

10.01.5 Analog Outputs

Data Update Rate: Using firmware version 7760, data is updated every 1 second.

Accuracy: The New Analog Output board provides an accuracy of ±0.25% of full scale.

Output Types: The board provides the output types in the following table via population of parts during build, that is, the board will have the same PC layout with two dash numbers. All outputs must be of the same type.

A)	-1 to +1 ma	Isolated	Active;	Into 5K ohm (max) resistor
B)	4 to 20 ma	Isolated	Passive;	12-40 Vdc supply voltage into a load resistance determined by the equation: $R_{L\,MAX} = \frac{V_{PS} - 11.6v}{20\ ma}$ where V_{PS} is the power supply voltage.

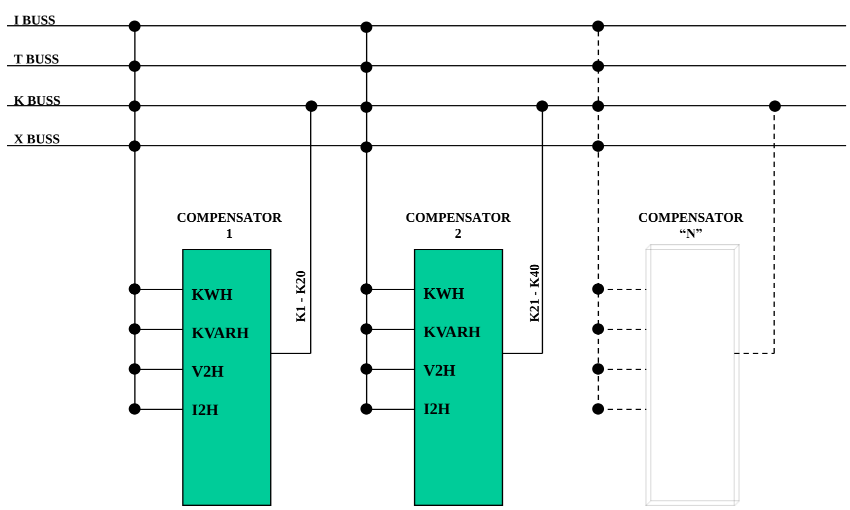
10.01.5 Communication Ports

11. Appedix

11.01.1 Power Transformer Losses

The Elite Meter can do three sets of losses and each set can have six sets of Iron and Copper constants. Each of the compensators will allow the user to bring in four signed Kwh and Kvarh values (which can be netted) along with voltages and currents. The Kompensator can calculated current if it is un-measured, this feature would be used if power values are being netted or the losses are downstream other side of the power transformer or downstream of transmission lines. In the standard configuration (default files): The inputs for Kompensator 1 come from two Totalizers (+/- Kwh) and (+/- Kvarh) along with the voltages and currents. The outputs (+/- Compensated Kwh and Kvarh along with Compensated Voltage feeds the inputs of Kompensator 2 and the same outputs form Kompensator 2 feeds the inputs of Kompensator 3. The outputs of Kompensator 3 are used for compensated values in the program. The diagram below shows how the Kompensators can be connected together. The default firmware supports 3 Kompensators. The reason for “Compensators” being spelled with a “K” is the meter already had a “C” bus when the multi-level TLC was developed. Therefore “Kompensator” and the outputs are “K” bus.

s



MULTIPLE COMPENSATION BLOCKS

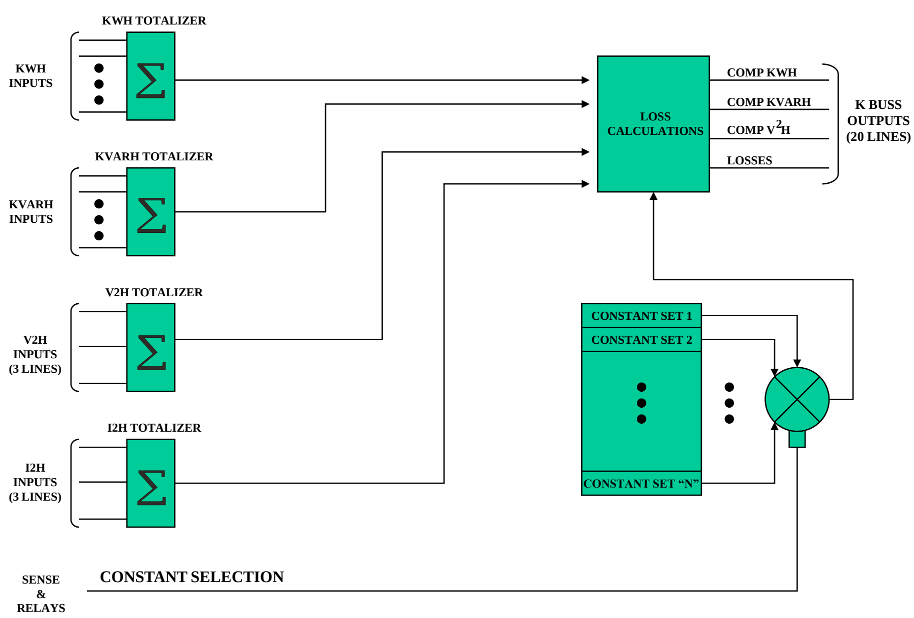
Naming (numbering) of Outputs for Kompensator 1:
K1- Compensated Kwh Delivered
K2- Compensated Kwh Received
K3- Compensated +/- Kwh
K4- Compensated Kvarh Q3
K5- Compensated Kvarh Q2
K6- Compensated Kvarh Q4
K7- Compensated Kvarh Q1

K8- Compensated Kvarh Received
K9- Compensated Kvarh Delivered
K10- Compensated +/- Kvarh
K11- V2H corrected
K12- V2H Filtered
K13- I2H Filtered
K14- Compensated Kvah
K15- Kwh Copper Losses
K16- Kvarh Copper Losses
K17- Kwh Iron Losses
K18- Kvarh Iron Losses volts squared (Line Losses)
K19- Kvarh Iron Losses volts to the 4th (Transformer Losses)
K20- Compensated V2H

Kompensator 2 has the same outputs however they are numbered K21-K40.
Kompensator 3 has the same outputs however they are numbered K41-K60.

The following diagram shows more details of the Kompensator's structure.

s

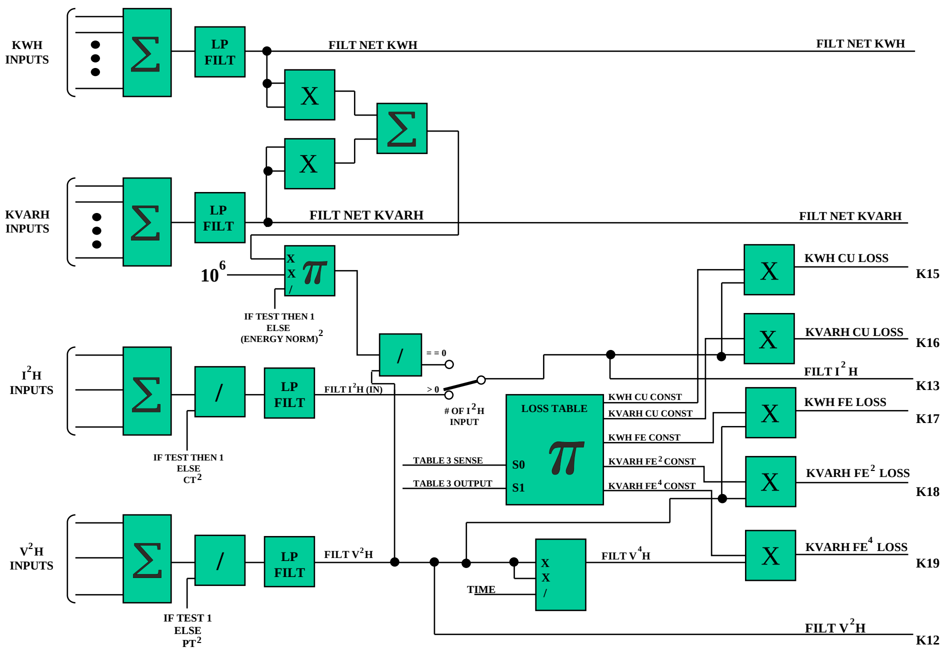


COMPENSATION BLOCK DETAIL

The diagram above shows the 4 summations for Kwh, Kvarh, V2H and I2H along with the sense inputs that are used to control which set of (6) constants that will be used for the calculations. The sense inputs could be connected to line status relays and the line loss calculations would change as lines were switched in and out.

The diagram below shows more details of the Kompensator's structure.

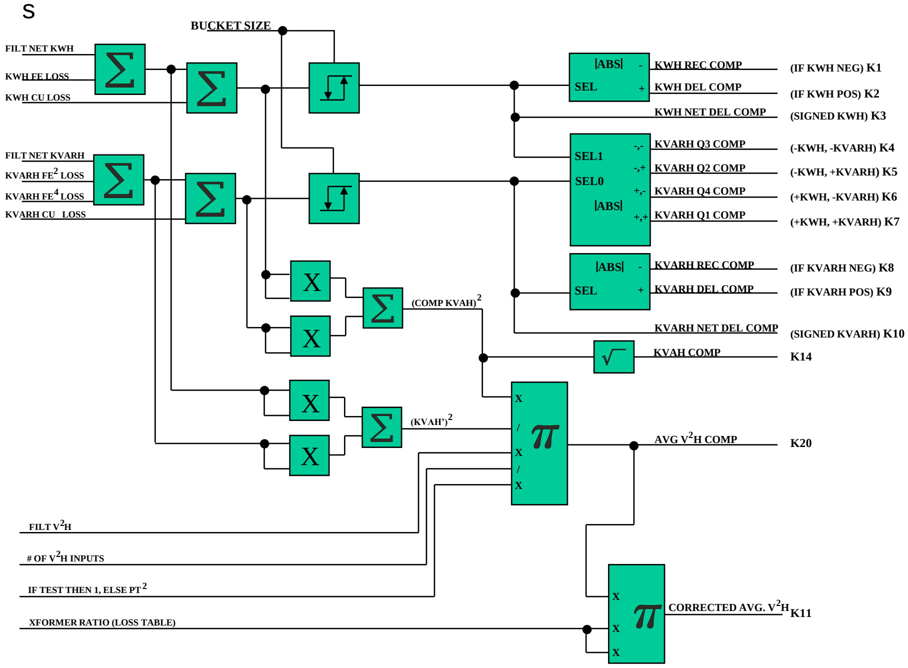
S



The diagram above shows the filter for Power, Voltage and Current. If you average the power you should also average the voltage and current. The filters would normally be used if the power values were coming from a non-real time source (pulse from an external meter). This helps smooth out granular data form pulses (Power) and improves the current calculations when the current values are not measured. You can also see the logic that looks at the number of currents to determent if the copper losses will use measured or calculated current. If the number of current equal zero the calculated current is used. You can also trace back and see where in the process the Kvah is calculated. The diagram starts showing some of the outputs from the Kompensator as well as seeing the control of the loss table where the six set of constants are loaded.

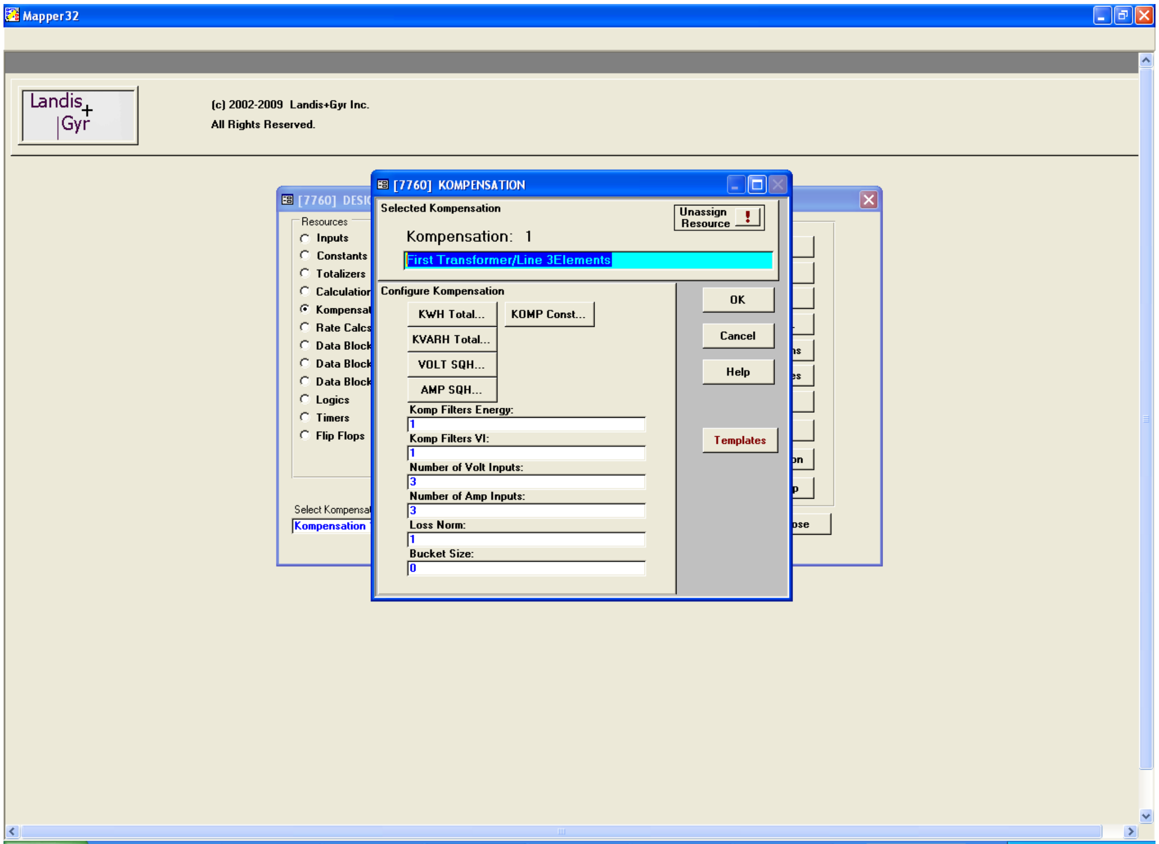
The diagram below shows more details of the Kompensator's structure.

s



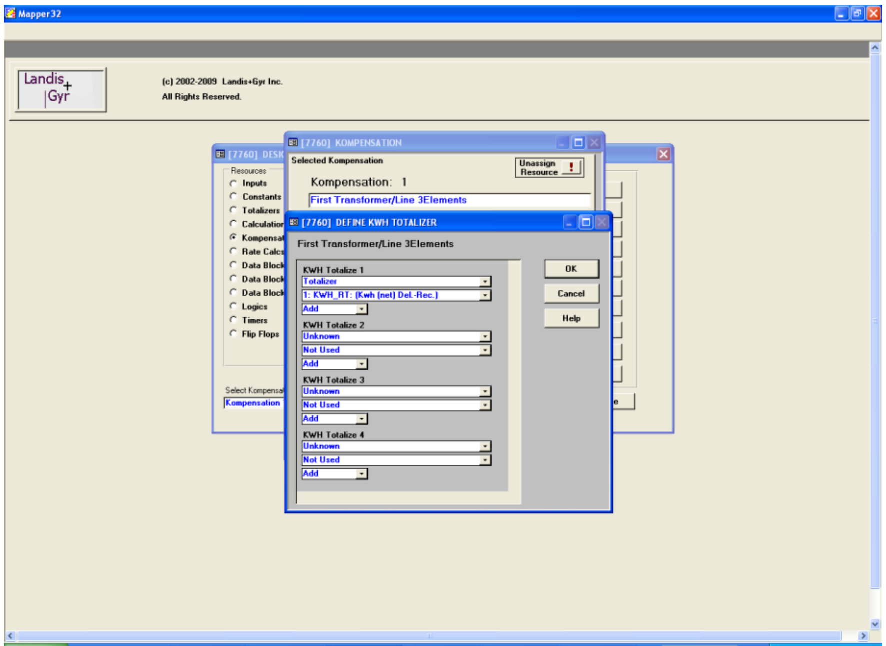
The diagram above shows the buckets which are used if the Power values are non-real time (pulses). This bucket allows the losses to accumulate up to the bucket size. If there is no measure power over the time it takes for the bucket to fill the losses will be applied to zero power values. This diagram also shows the balance of the Kompensator outputs.

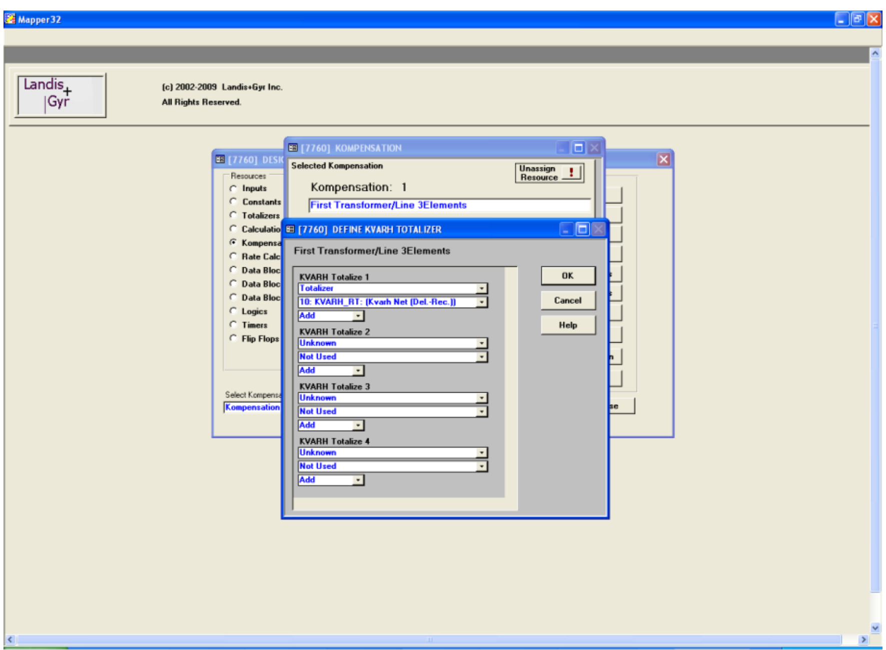
DEFAULT CONFIGURATION KOMPENSATOR 1 (Mapper32)



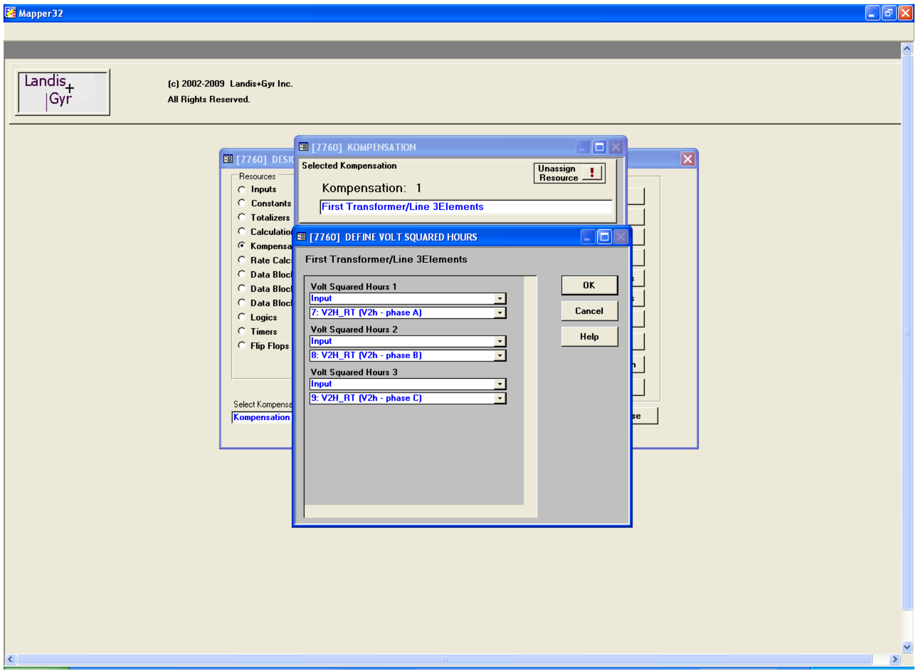
This shows the first screen which allows the user to select the Kwh, Kvarh, Volt Square and Amp Square inputs. This can be seen in more detail in the following screen. The user could also set the filters and the bucket size. The user could also enter the number of voltages, currents and loss normalizations (IT IS NOT RECOMMANDED) on this screen. The values should be calculated within MAXcom based on the information from the power transformer test sheet and the site information. MAXcom will then enter correct values based on the provide information. MAXcom will also calculate and enter all of the Komp Constants (THE CONSTANTS SHOULD NOT BE ENTERED ON THIS SCREEN). This will allow the user to have one file for all of their TLC meters and the losses values to change base on site and transformer information at the time the meter is programmed.

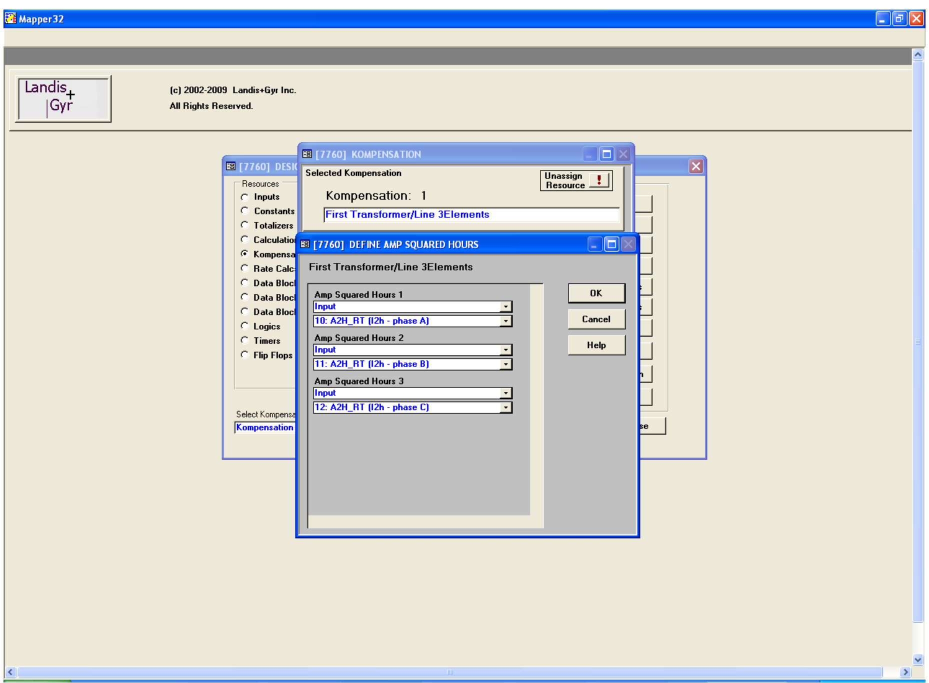
The next two screen shots show the set-up of the power inputs and the ability to add or subtract the value which will allow the user to net loads before calculating the losses. If the user is netting power values they will need to use calculate current (set number of currents to zero) and the inputs to “Unknown/Not Used”.



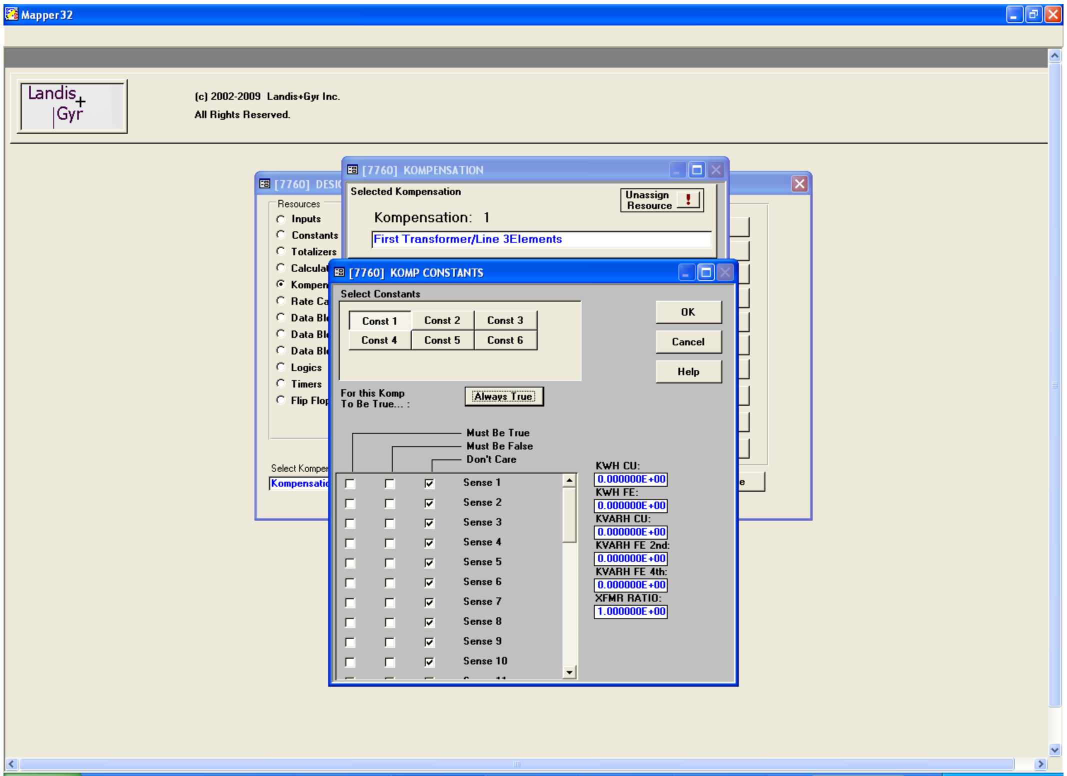


The next two screen shots show the set-up of the Voltage and Current Squared inputs. They can be changed by changing the number of voltages and currents within MAXcom.





The next screen shots show the constants; normally they will be zero unless the file came out of a meter in the form of a “tbf” file. The constants will be calculated and loaded into the meter by MAXcom. The user will need to set-up the logic to control which set of constants will be used by the meter if more than one set of constants are to be used. The power transformer ratio will also be calculated and loaded by MAXcom.

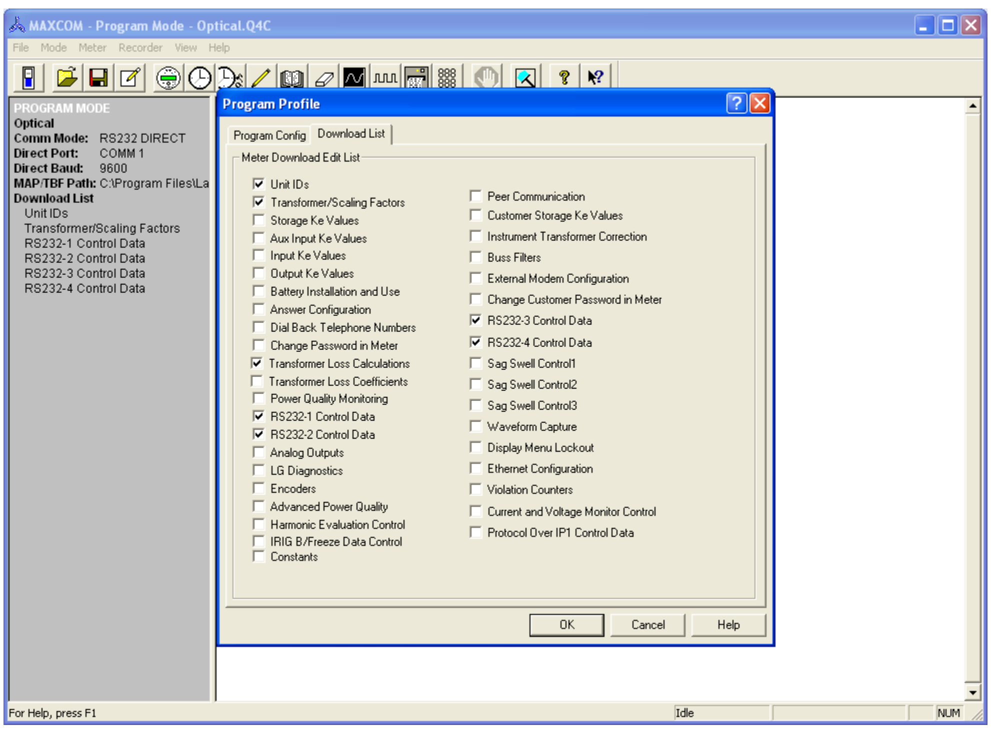


PROGRAMMING LOSSES INTO THE METER

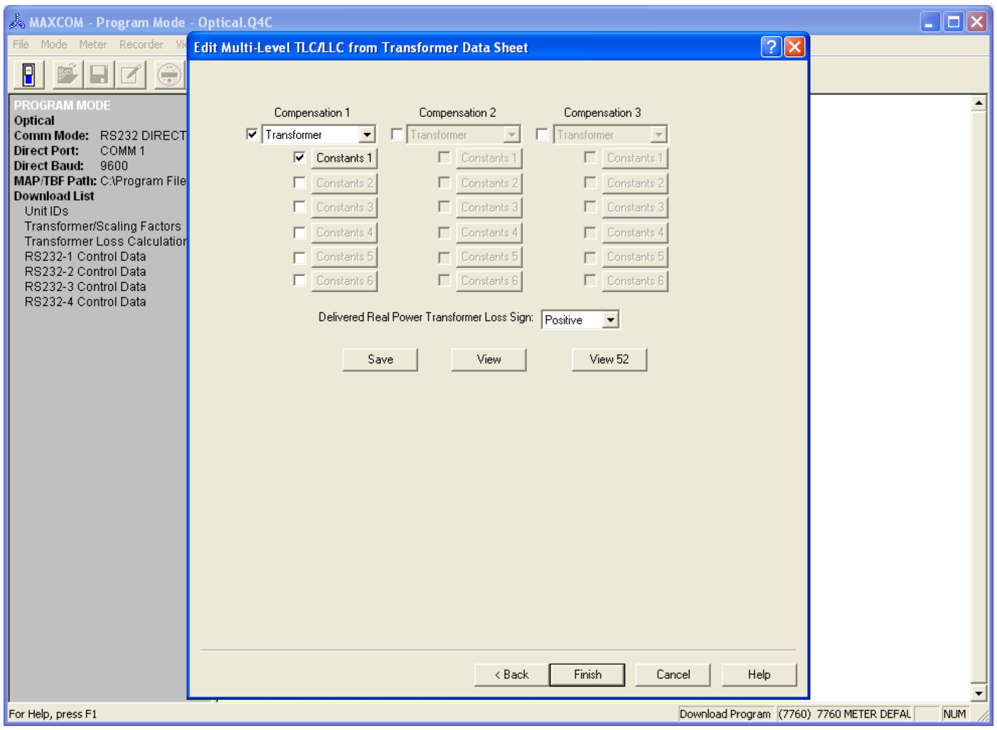
The losses constants are normally calculated and loaded into the meter by MAXcom. When entering the information into MAXcom it is recommend the user enter the values using the “Transformer Loss Calculations” method. If the user must use the “Transformer Loss Coefficients (percents)” and they are programming a form 35 meter 3-phase 3-wire they most know if the percents were based on a 3-phase or single phase (series) calculations. If the user is programming a form 36 meter 3-phase 4-wire the percents most of been calculated based on 3-phase calculations NOT single phase (series). The secondary voltage and current values that are entered must be the values that were used when the percent losses were calculated.

MAXcom CONFIGURATION

The first requirement when you are going to do Transformer Losses is select the TLC option in the ‘Program Profile Download List”. The screen below shows “Transformer Loss Calculations” has been selected. By making this selection the program will require the user to enter information on both the power transformer and the metering (site) installation.



After the user selects the program that is to be downloaded (programmed) into the meter MAXcom, will request both transformer and site information using the following screens. In the following example, only one “compensation” and one set of “constants” have been selected. The pull down menu next to “transformer” will allow the user to select either transformer or line for the type of compensation to be done. The other pull down menu will allow the user to select between adding and subtracting the losses from the delivered power. If losses are added to delivered power they will be subtracted from received power and if they are subtracted from delivered they will be added to received power. The next step would be to click on the constants (tab) button.



After clicking on “constants” the user will get the next screen.

The “Meter Side Wiring:” pull down menu will allow the customer to select “Delta, Wye, Open Delta, Single Phase-One Element, 4-wire Delta or Single Phase-two Element” this is the way the transformer is being metered.

The “Transformer Type:” pull down menu will allow the customer to select their transform bank configuration. The selections are “one single 3-phase Transformer” or a “bank of single phase Transformers”. If a “bank of Single Phase Transformer is selected the user will then be able to enter information for each of the transformers. If the installation requires uses of a form 36 meter the user would check the box for the form 36S/6A. The following information is base on a meter being wired as a “Wye” meter and one 3-phase transformer.

Site Information

Potential Transformer Turns Ratio: 7200 to 120 VT would be 60
Current Transformer Turns Ratio: 1200 to 5 CT would be 240

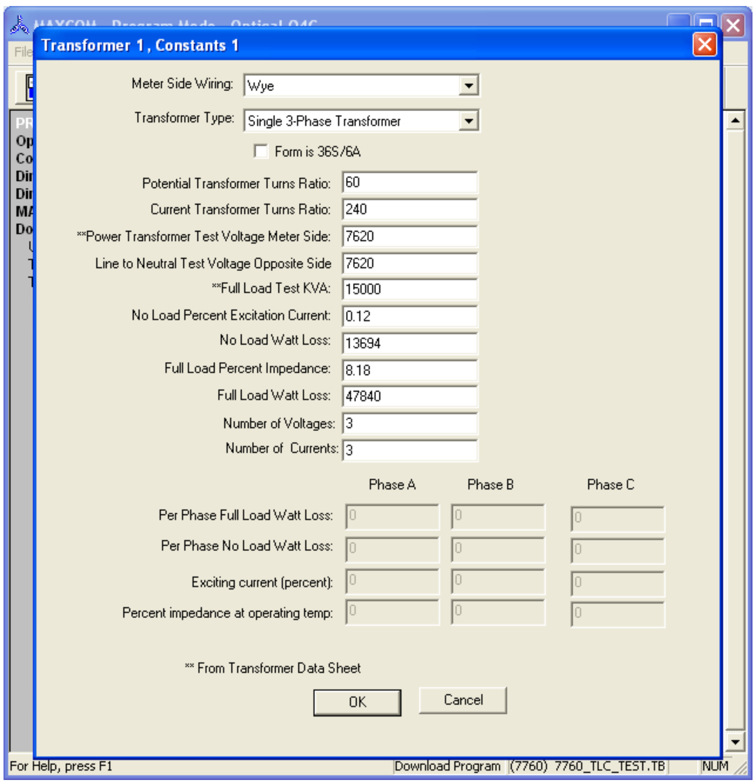
Transformer Information

Power Transformer Test Voltage: This is the voltage that was applied to the transformer for the “NO LOAD” (Iron) test. The information comes from the transformer data sheet. This IS NOT the VT voltage. Example: The no load data was taken with 7620 volts applied to the transformer.
Line to Neutral Test Voltage Opposite Side: This name will change to Line to Line if the “meter side wiring” is changed to Delta. This information is only required if the next Kompensator is being used. If the second Kompensator is not being used enter the same value that was used for the “transformer test voltage”. Example: 7620 Volts
Full Load KVA: This is the KVA that was applied for the Load Loss (Copper) test from the transformer data sheet. Example: 15000 Kva
No Load Percent Excitation Current: This value comes from the transformer data sheet. Note, the full load Kva time the percent excitation current must be larger than the “No Load Losses” watts. Example: 0.12%
No Load Watts Loss: This value comes from the transformer data sheet. Some data sheets reports this value in Kw, however the value must be entered in Watts. Example: 13694 Watts
Full Load Percent Impedance: This value comes from the transformer data sheet. Note, the full load Kva time the percent excitation current must be larger than the “Load Losses” watts. Example: 8.12%
Full Load Watts Loss: This value comes from the transformer data sheet. Some data sheets reports this value in Kw, however the value must be entered in Watts. Example: 47840 Watts
Number of Voltages: This the number of voltage coils that the meter is (seeing) using. Examples: When a form 9S is used to meter a “Wye” service the answer is 3. When the same 9S meter is used to meter a 3-wire “Delta” service the answer is 2. When a form 36S is used to meter a “Wye” service the answer is 3. When the same 36S meter is used

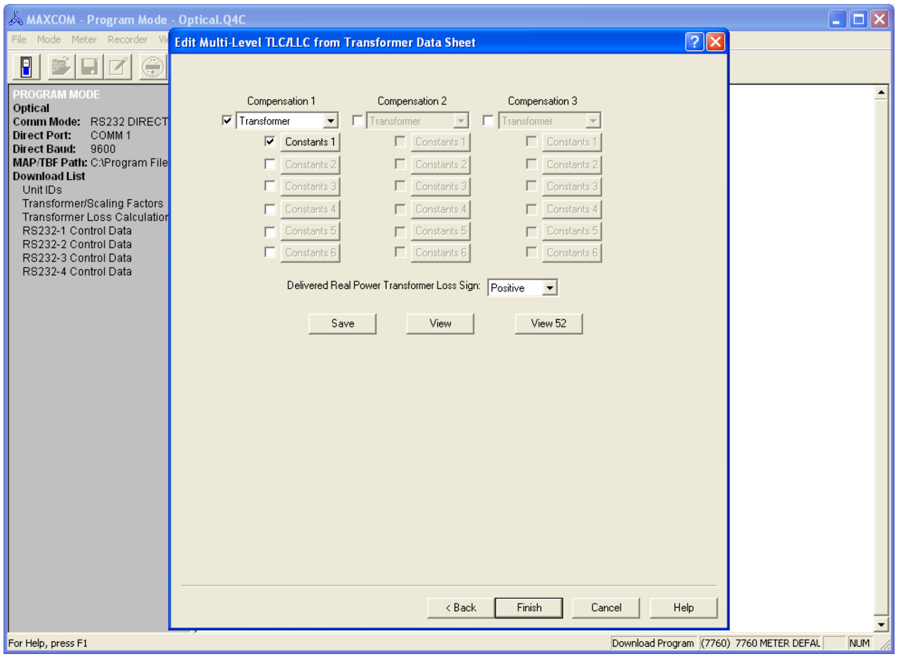
to meter a 3-wire "Delta" service the answer is 2. When the same 35S meter is used to meter a 3-wire "Delta" service the answer is 2. The answer is always based on the number of voltages the meter is (seeing) using.

Number of Currents: This the number of current coils that the meter is (seeing) using. Examples: When a form 9S is used to meter a "Wye" service the answer is 3. When the same 9S meter is used to meter a 3-wire "Delta" service the answer is 2. When a form 36S is used to meter a "Wye" service the answer is 3. When the same 36S meter is used to meter a 3-wire "Delta" service the answer is 2. When the same 35S meter is used to meter a 3-wire "Delta" service the answer is 2. The answer is always based on the number of currents the meter is (seeing) using.

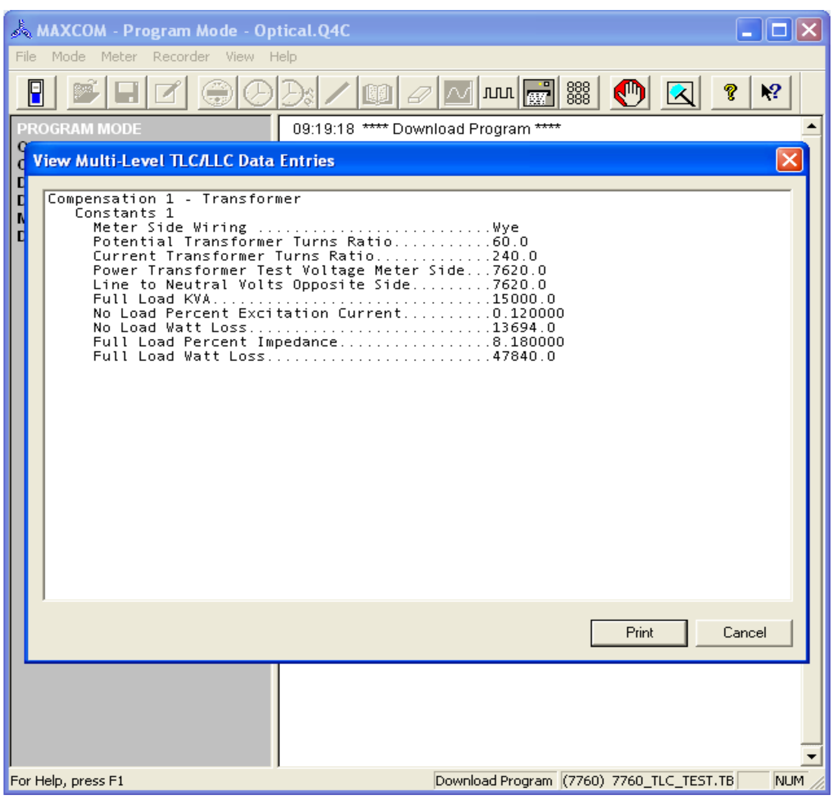
Then Click "OK"



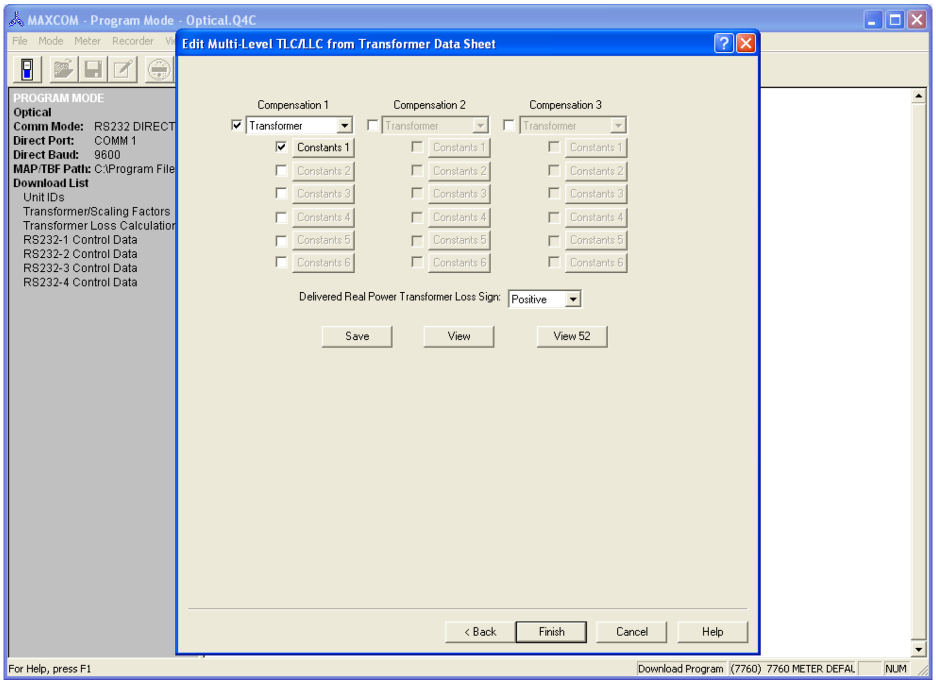
After clicking “OK” you will be returned to the following screen.



You can click “View” and review the information that you entered. After reviewing the information click “Cancel” to be returned to the previous display.

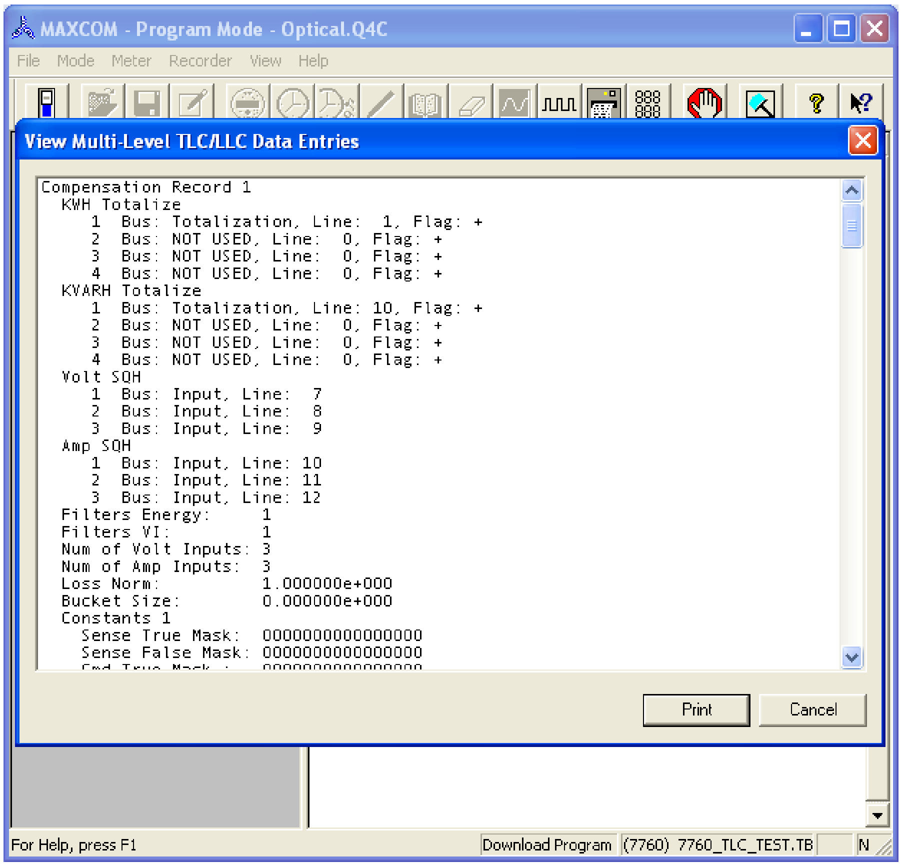


Before the user can view the data (table 52) that will be entered into the meter by MAXcom, they must click “Save”. Then the user can click “View 52” and see the data that will be placed in the meter.



This screen displays shows how the Kompensator will be configured.

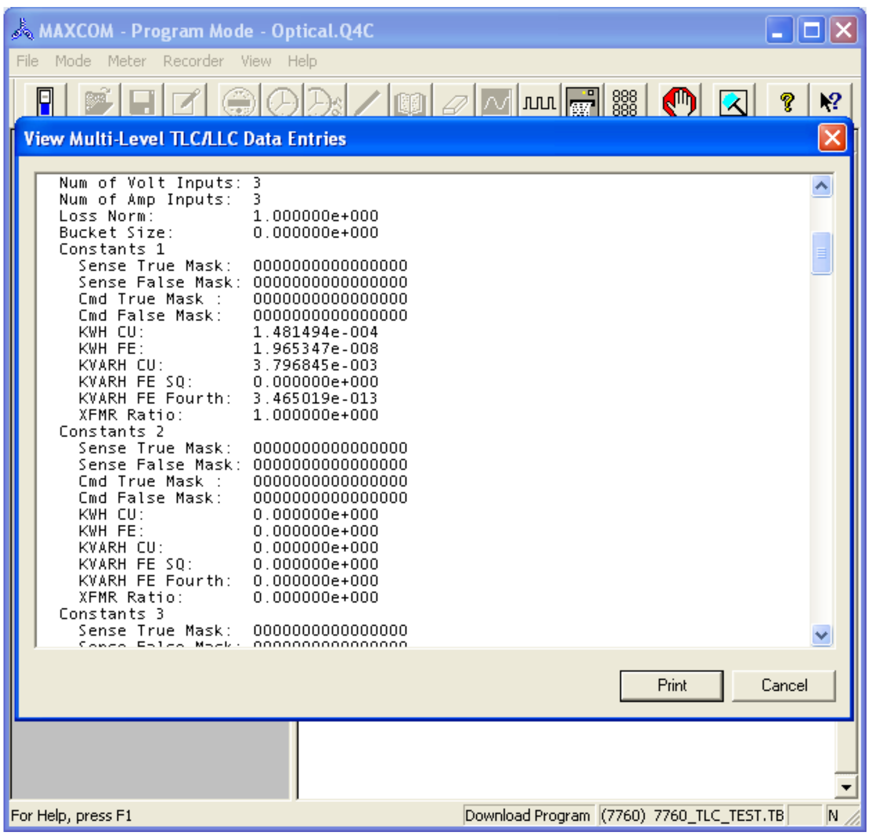
Sources: Kwh, Kvarh, Volts Square and Amps Square Hours
Filters: Energy and VI (Volts and Currents)
Number of: Volt and Amp Inputs



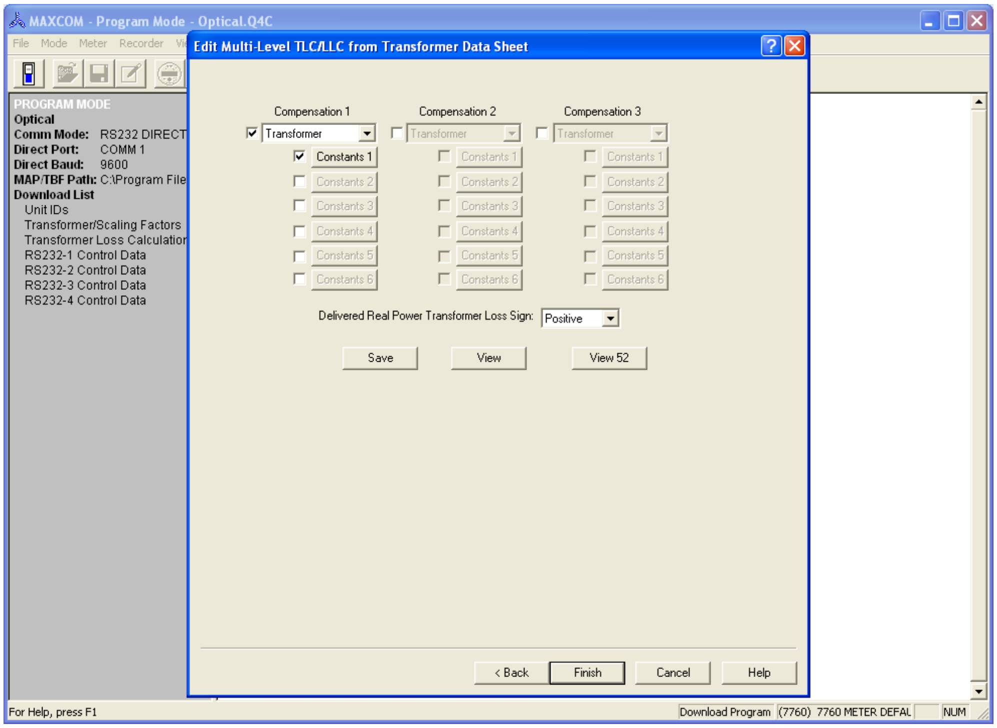
Kompensator configuration continues

Constants: All six sets of constants and the logic for the control (sense) of when each set of constants will be used.
Kwh Cu (copper) Constant: Example: 1.481494e-004
Kwh Fe (Iron) Constant: Example: 1.965347e-008
Kvarh Cu (copper) Constant: Example: 3.796845e-003
Kvarh Fe (Iron) SQ Constant: Example: 0.0 (used for line losses)
Kvarh Fe (Iron) Fourth Constant: Example: 3.465019e-013 (used for transformer losses)
XFMR Ratio: Example: 1 (This is the ratio of the power transformer) This will be the ratio between "Power Transformer Test Voltage Meter Side" and Line to ? (Neutral in our example) Example: 7620 to 7620 equals 1

Only one set of constants were calculated based on the information supplied to MAXcom. After reviewing the information click "Cancel" to be returned to the previous display.



When the user is satisfied and clicks "Finish", the Kompensator will be configured and the loss constants will be load into the meter.



TESTING Please review section 9 of this manual

Kwh & Kvarh

Testing the accuracy of the meter's Kwh and Kvarh should be done using the LEDs (see Elite Accuracy Testing) in the optical port on the face of the meter or by setting output relays to calibrated Kwh & Kvarh.

Note: The Kwh & Kvarh values are calculated from the calibrated voltage, current inputs of the meter.

Compensated Kwh & Kvarh

Testing the accuracy of the meter's compensated Kwh and Kvarh should be done using the display in the normal or test mode as well as using the LEDs (see Elite Accuracy Testing) in the optical port. The output relays should not normally be used to test compensated values because of the amount of time required. The following displays can be used:

Kwh

Kvarh

Compensated Kwh

Compensated Kvarh

(With these four displays you can calculate the losses)

% Kwh Copper

% Kwh Iron

% Kvarh Copper

% Kvarh Iron

% Compensated Kwh with losses

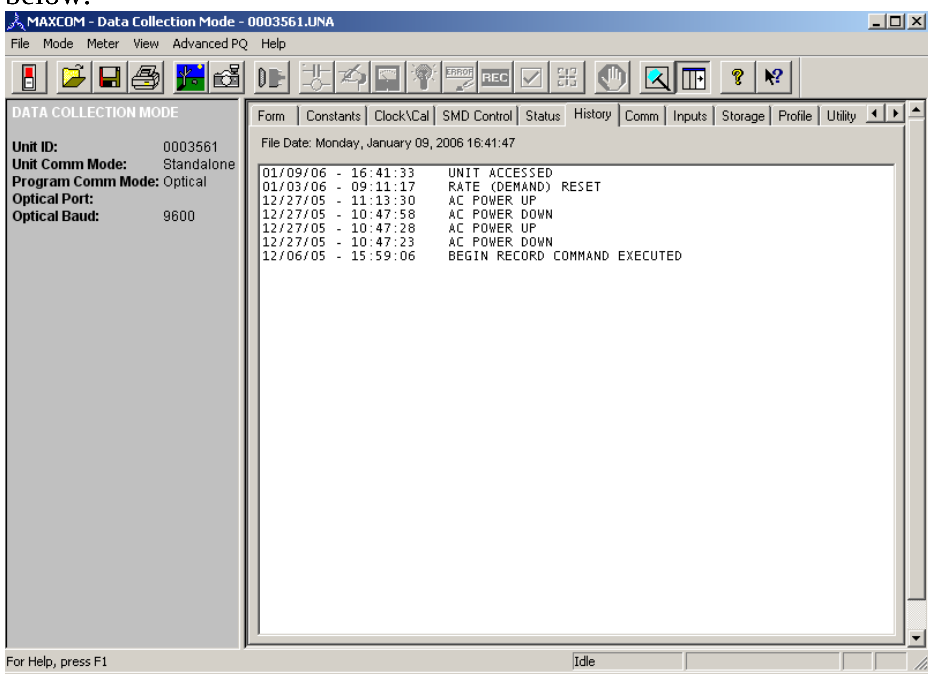
% Compensated Kvarh with losses

(With these displays you have the percent correction displayed in real time)

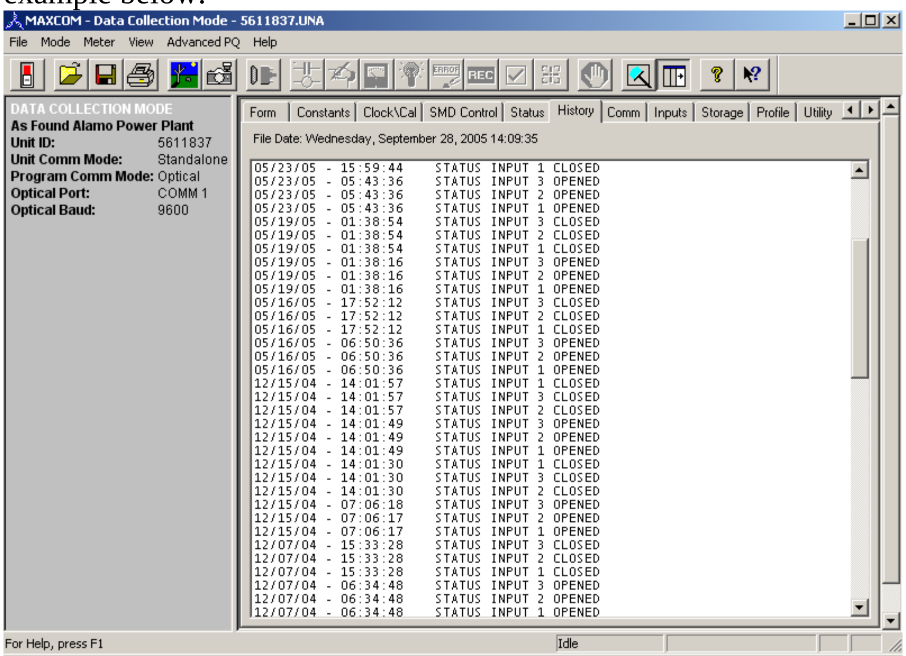
Note: All of the percent values are referenced to the tested Kwh & Kvarh values with in the meter. The copper and Iron losses are calculated from the same voltages and currents used for the Kwk & Kvarh values in the meter. The data flow diagram shows the how all of the compensated values are referenced back the measured un-compensated Kwh & Kvarh values with in the meter.

11.02.1 Power Quality

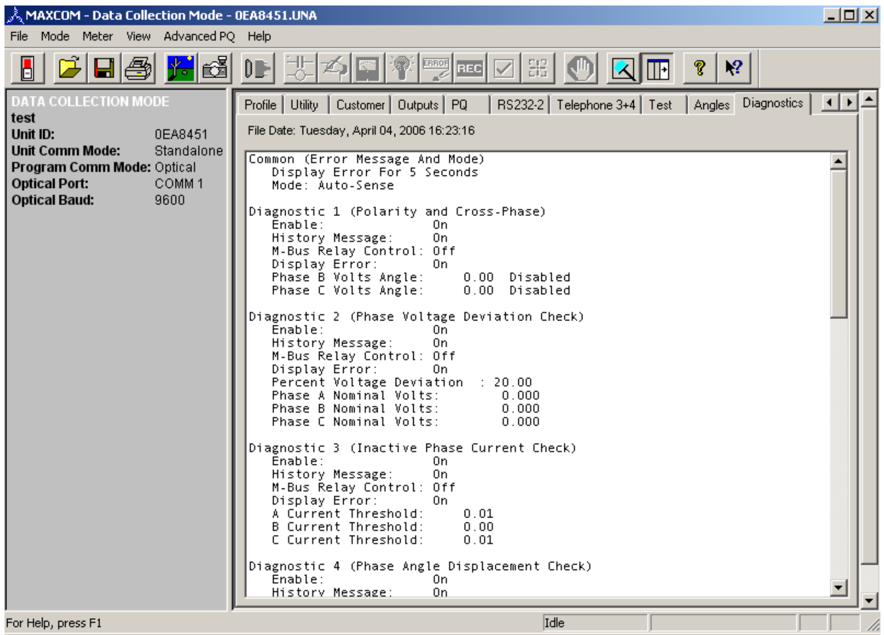
1. **Standard**
    a. LOSS OF AS POWER: The Elite meter monitors the voltage to the electronics of the meter and reports this as “AC POWER UP/DOWN”. The amount of time the meter is powered down is recorded as battery minutes in table 2 and battery seconds in table 101. The “AC Power up/down is reported as an event in the history buffer. The amount of time that the Power must be off before the power down is reported as an event is programmable (Default is 5 seconds). The number of times there has been a loss of power is counted if the power down lasts less than the event time. Maxcom software reports the history buffer as per the example below.

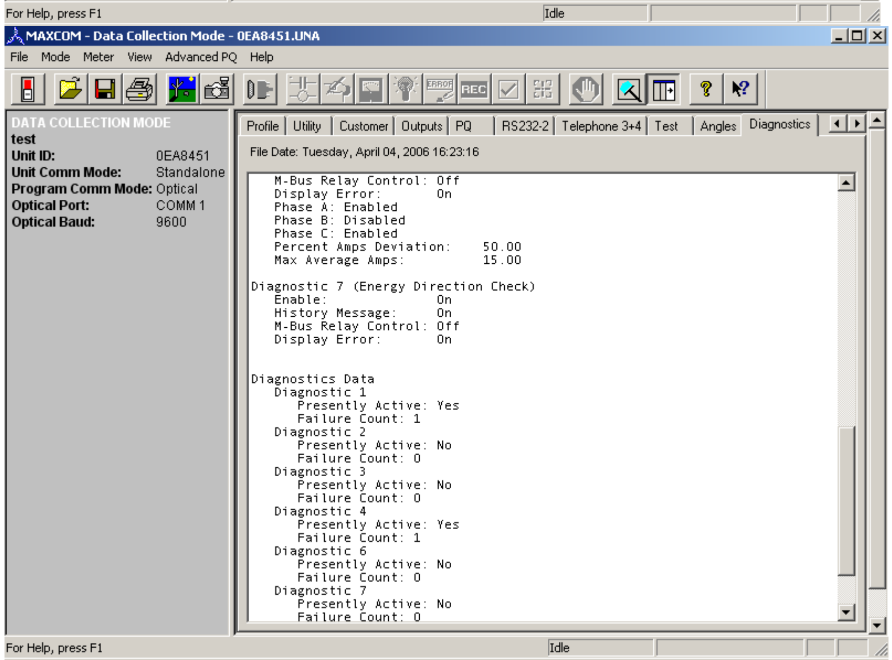


b. MISSING PHASE: Each of the voltage inputs are assigned to a status input (table 3). The change of a status input is reported as an event in the history buffer and the status inputs can also be used for logic control within the meter. This would allow the customer to develop a program that would calculate the power in a phase with a missing voltage and accumulate the calculate values in a separate register (could be called corrected register). Maxcom software reports the history buffer as per the example below.

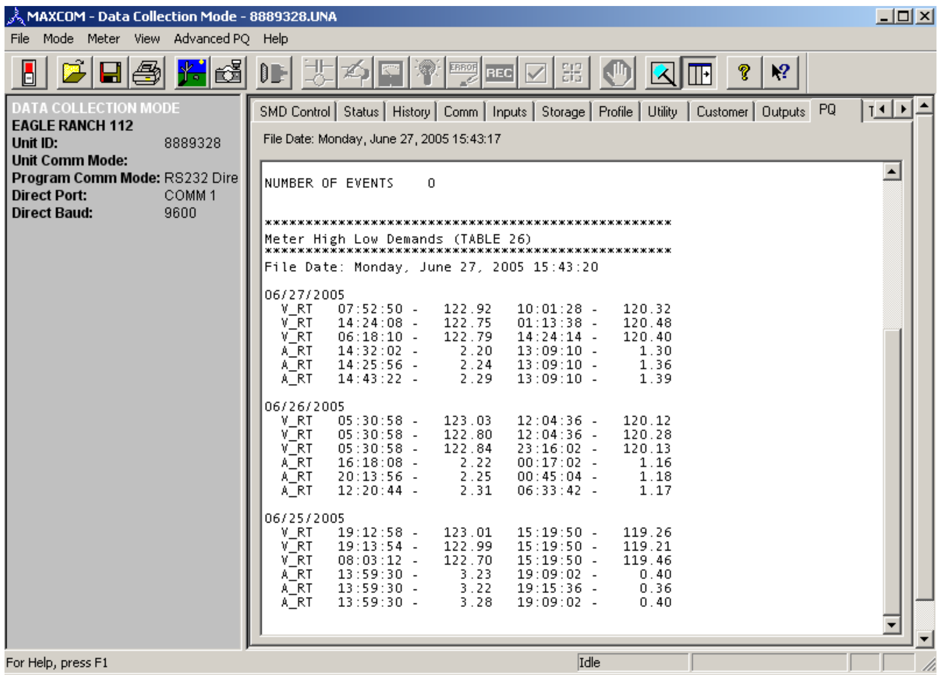


c. Service diagnostics are performed within the meter using the standard L&G diagnostics (Tables 56 & 57). Maxcom software reports the diagnostics tab as per the following examples.

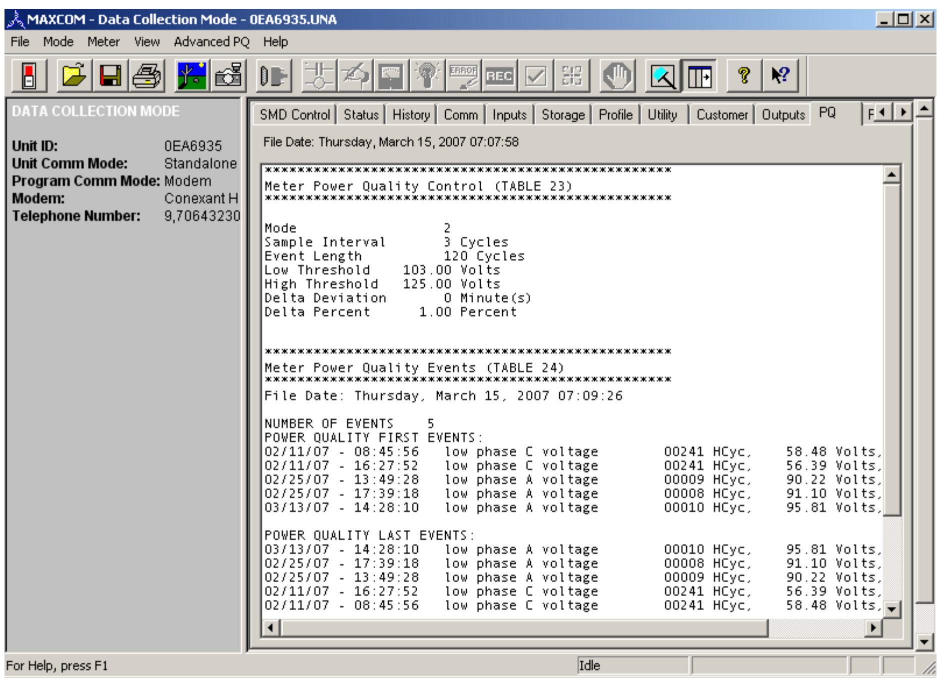




d. DAILY HIGHS AND LOWS: The Elite meter keeps three days (rolling) of the one second highs and lows of six values. The default is set to store the three voltages and the three currents (table 25 & 26). The data can be viewed using Maxcom. Maxcom software reports the high/lows under the PQ tab as per the following examples.



e. SAGS AND SWELLS (PQ): The system allows two modes of operation. The first mode (1) will capture the sag/swell (voltage only) and duration of the event (reported down to 0.5 cycles) along with the date and time of the event. The meter can store 512 events. The events will be divided into two groups. The first 256 events which will be stored until cleared while the next 256 events will be the last events captured (the last events will wrap around, newest replacing oldest). The other mode (3) works the same as mode 1 except, the current will be captured at the same time as the voltage. The sag or swell of the voltage causes the capture of both the voltage and current. The sag and swell set points are programmable in Mapper32 and can be edited using Maxcom software. Note: When Advanced Power Quality is enabled, the sag/swell thresholds will be overridden by the values in Sag/Swell 1 of the advanced Power Quality. Maxcom software reports the high/lows under the PQ tab as per the following examples.



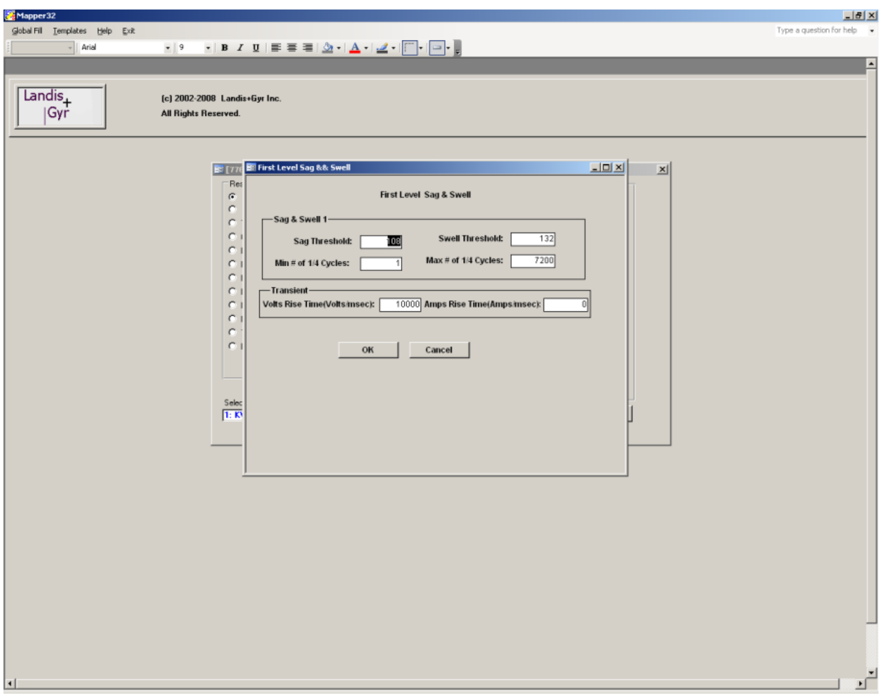
f. THD: The meter also has the capability to display and record per-phase THD values.

g. Event Dial In: Programmable values of voltage, current and power can be used to trigger the meter to call into the central station or other “Event Monitoring” software.

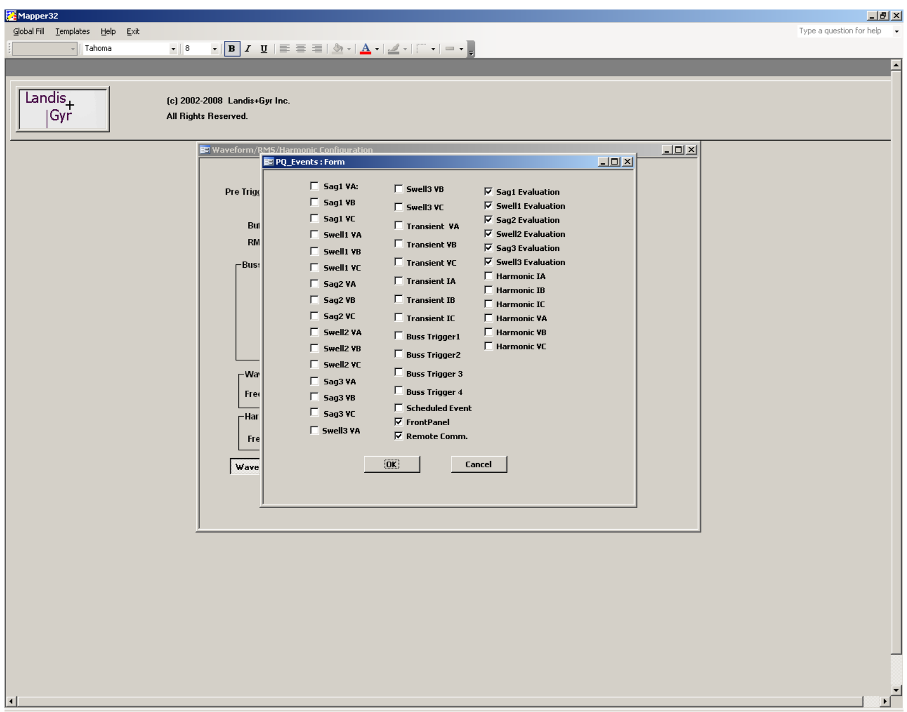
h. Event Relays: The meters relays can be programmed to operate based on voltage, current and power values.

2. Advanced Power Quality

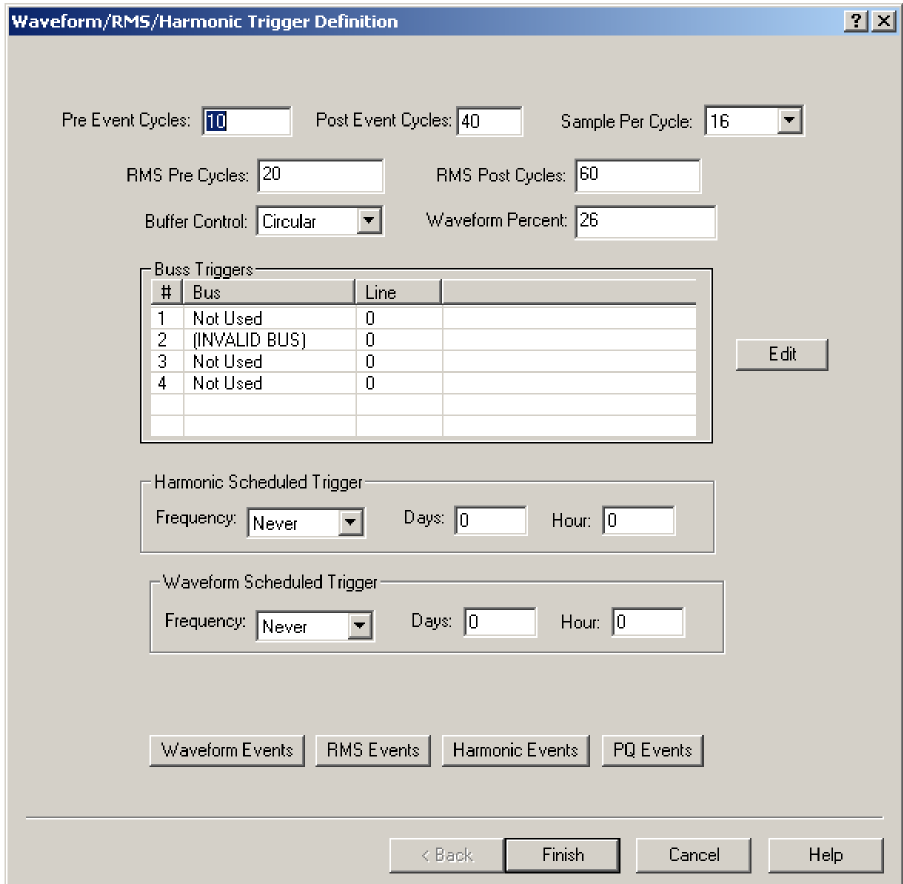
a. SAG AND SWELLS: When advanced power quality is enabled you will be allowed to set three independent sets of sag and swell ranges. The Advanced Power Quality will capture the sag/swell and the duration of the event (reported down to 0.25 cycles) along with the date and time of the event. When setting the values for each of the sag and swells take care that the ranges of the sag and swells do not overlap. If the ranges overlap and an event occurs that crosses more than one set of thresholds, only the worst will be reported. Please note the set points of sag and swell 1, overrides the trigger values in the sag and swell (PQ) none advanced. Sag and swell events can also be used to trigger captures of Waveforms, RMS and Harmonics events. Transients can also trigger captures. The event trigger points can be programmed using Mapper32 (program development software) or they can be programmed or edited with MAXcom (meter programming software).



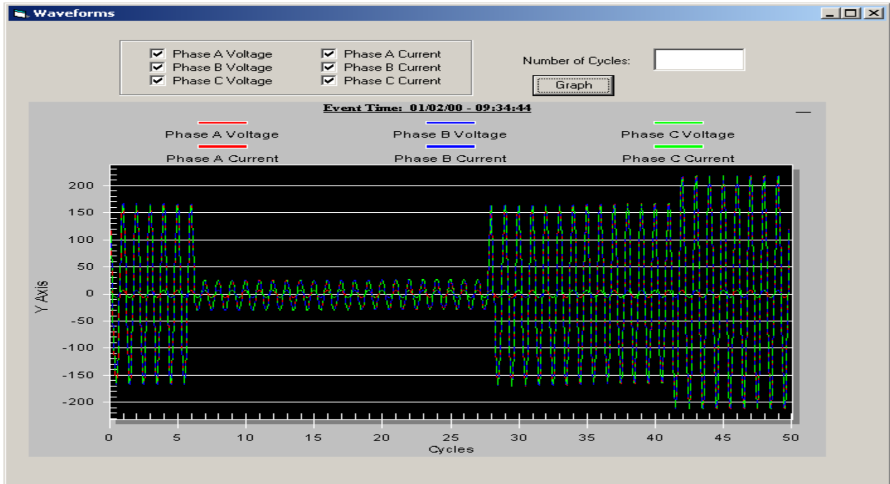
b. WAVEFORM CAPTURE: When enabled the meter can perform a capture of both the voltage and current waveforms. The capture can be triggered by the meter based on an event, remotely or by using the buttons on the meter. A total of 512 captures is possible with the first 256 “oldest” stored until being cleared and 256 of the newest events stored in circler memory with the oldest being overwritten be the newest. The user can select the number of Pre-event (Max 30) cycles to capture and the number of Post-event (Max 60) cycles to capture. The samples per cycle are also selectable from 16-256 samples per cycle in the following steps (16, 32, 64, 128, 256). The ability of controlling which events are captured and stored help reduce the amount of data which is stored and that needs to be downloaded to a central station. Please note, if front panel is not select the meter will still capture and display on the meter face however the event will not be stored in memory. The parameters can be programmed using Mapper32 (program development software) or they can be programmed or edited with MAXcom (meter programming software).

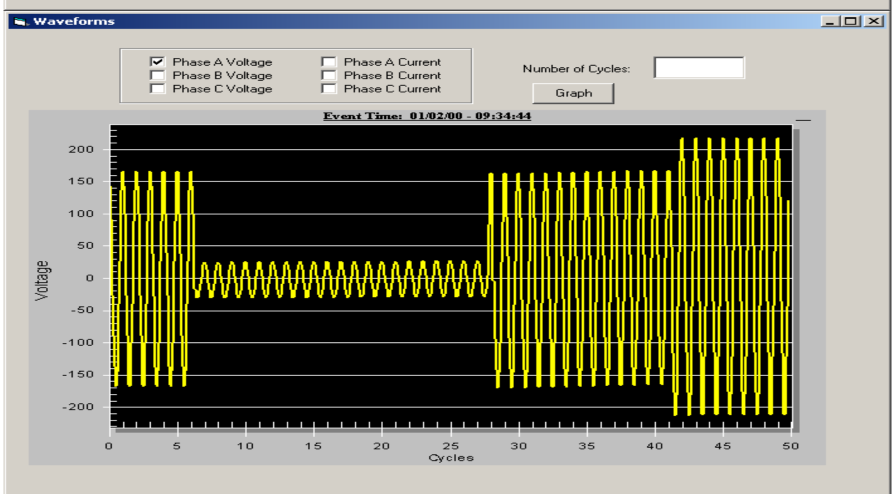


The following screen shows the set-up of waveform captures.

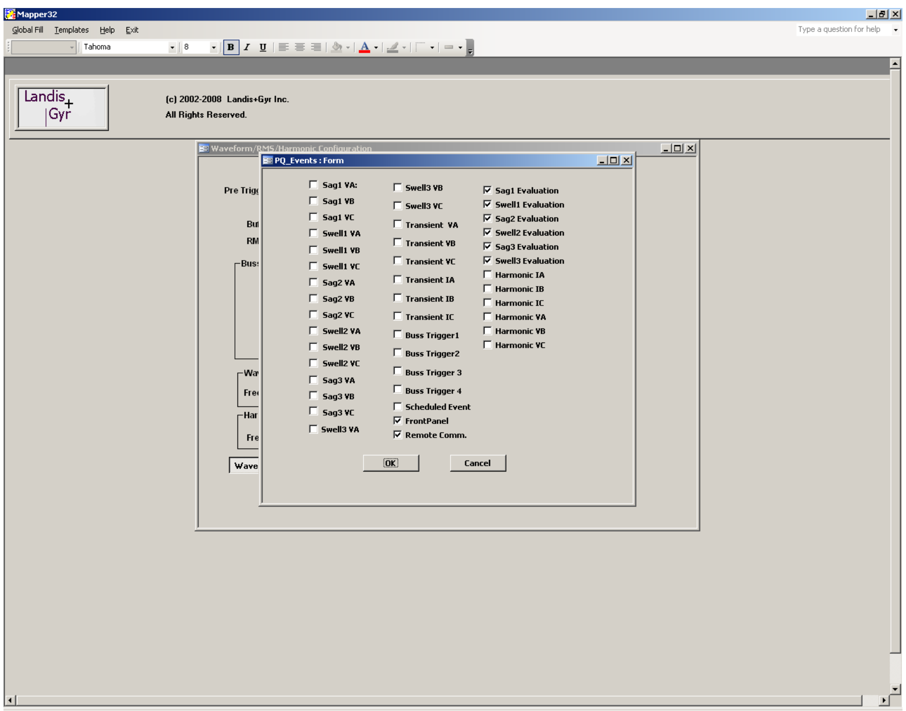


The following are some examples of waveforms.

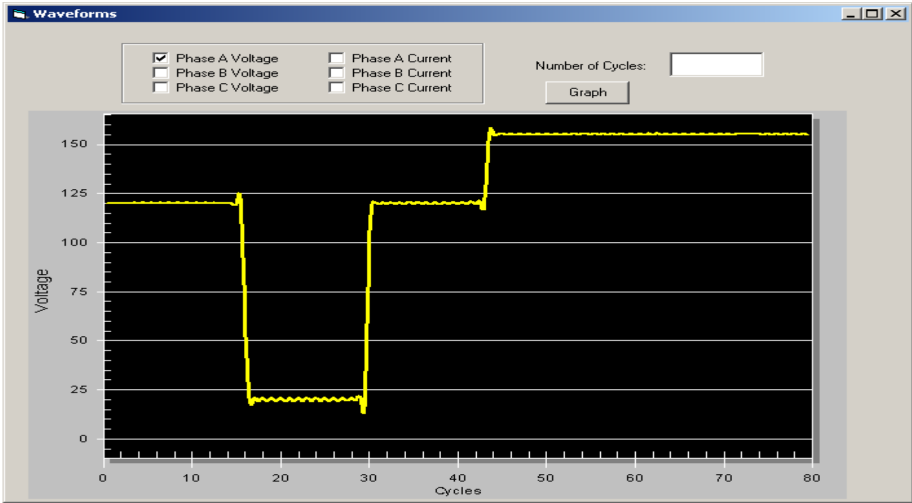




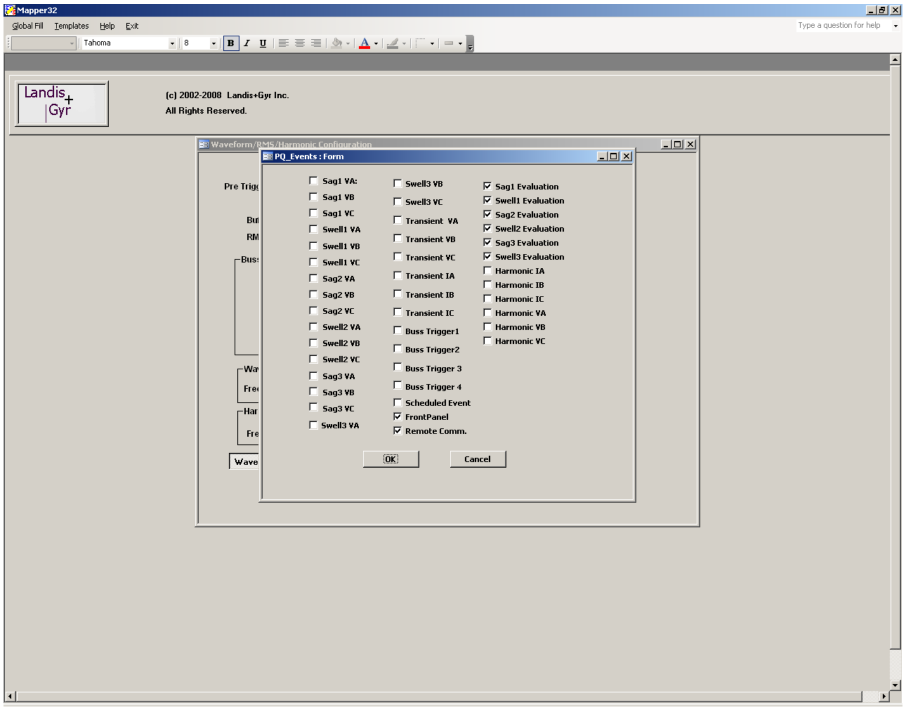
c. RMS CAPTURE: When enabled the meter can perform a capture of both the voltage and current RMS waveforms. The capture is triggered by the meter based on an event. The user can select the number of Pre-event (Max 600) cycles to capture and the number of Post-event (Max 6144) cycles to capture. A total of 512 captures is possible with the first 256 “oldest” stored until being cleared and 256 of the newest events stored in circler memory with the oldest being overwritten be the newest. A total of 512 captures is possible with the first 256 “oldest” stored until being cleared and 256 of the newest events stored in circler memory with the oldest being overwritten be the newest. The event trigger points can be programmed using Mapper32 (program development software) or they can be programmed or edited with MAXcom (meter programming software). The event triggers are enabled using the following screen.



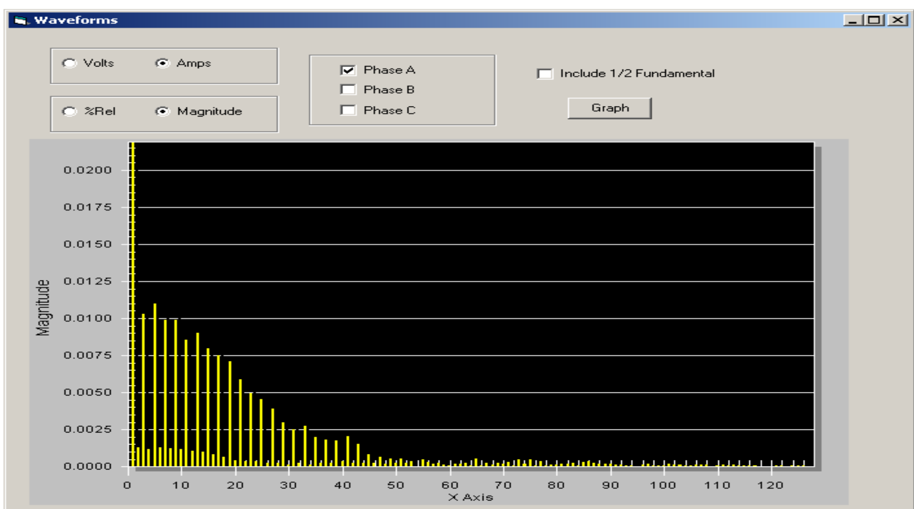
The following are some examples of RMS captures.



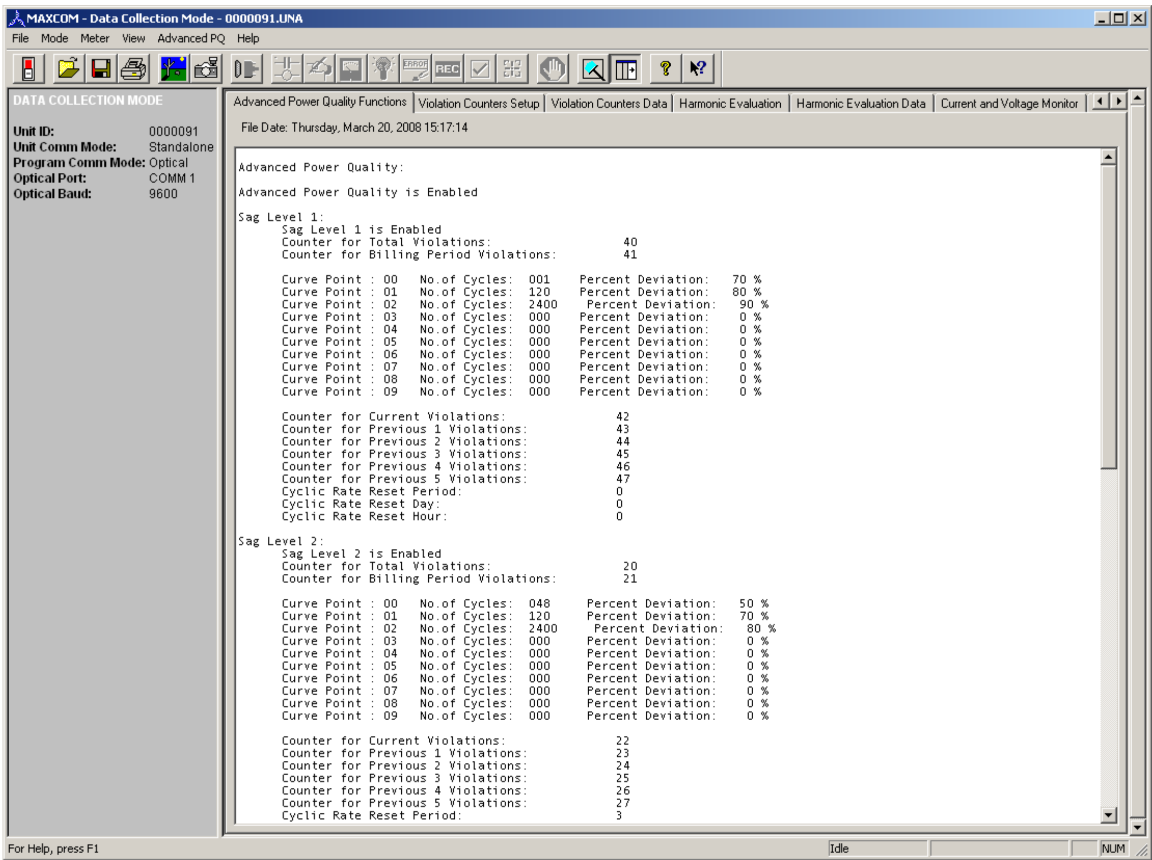
d. HARMONIC CAPTURE: When enabled the meter can perform a capture of the harmonics in both the voltage and currents. The capture can be triggered by the meter based on an event, remotely or by using the buttons on the meter. A total of 512 captures is possible with the first 256 "oldest" stored until being cleared and 256 of the newest events stored in circler memory with the oldest being overwritten be the newest. A total of 512 captures is possible with the first 256 "oldest" stored until being cleared and 256 of the newest events stored in circler memory with the oldest being overwritten be the newest. The event trigger points can be programmed using Mapper32 (program development software) or they can be programmed or edited with MAXcom (meter programming software). The harmonic evaluation will be done over a 2 cycle sample when the request comes from the front panel. Please note, if front panel is not select the meter will still capture and display on the meter face however the event will not be stored in memory. The function of controlling which events are captured and stored help reduce the amount of data which is stored and that needs to be downloaded to a central station. The event triggers are enabled using the following screen.



The following is an example of a Harmonic Capture.

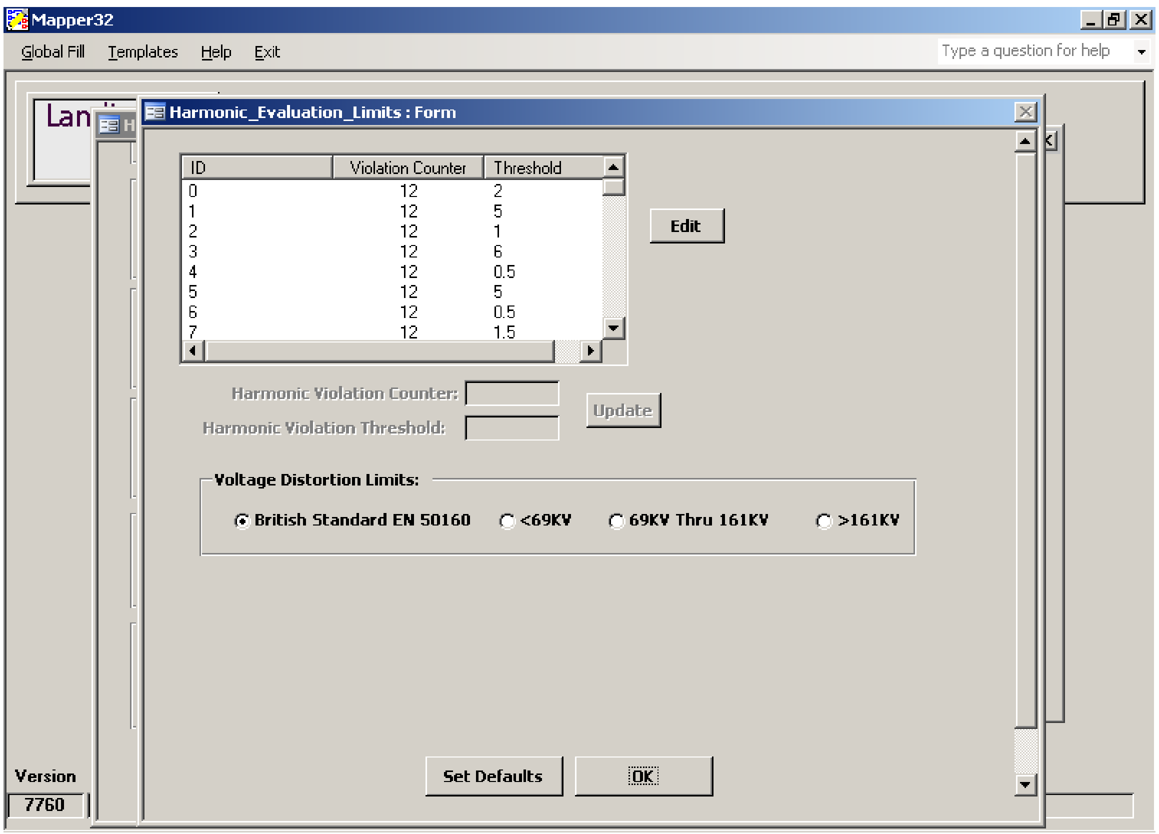


3. **Advanced Power Quality Analysis**
   a. VOLTAGE SAG/SWELL ANALYSIS: The system has the ability to perform 3 sets of sag and swell analysis simultaneously with each set supporting 10 points on a graph (CBEMA/ITIC, SEMI or CUSTOM). The system keeps track of the number of violations in one of 256 violations counters that are customer selectable. This allows the analysis to be done in the meter reducing the amount of data that you may need to bring back. The system stores the total number of violations, violations for billing period, as well as current violations and the 5 previous sets of violations in counters based on cyclic resets. The meter can be programmed to capture an event based on a change in any of the 256 counters.

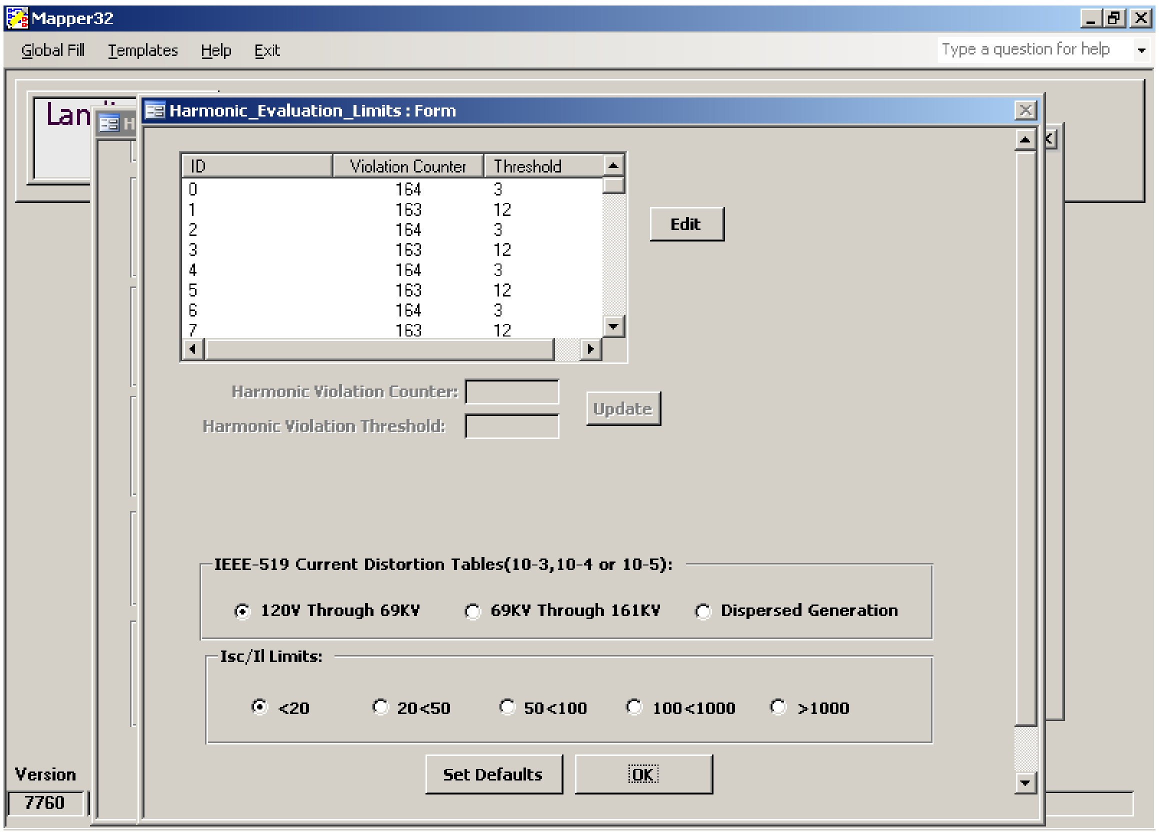


b. HARMONIC ANALYSIS: The system has the ability to perform harmonic analysis simultaneously on each phase voltage and current with thresholds or each harmonic up the 63rd (user programmable). This can supports standards like (IEEE-519 and British Standard EN 50160) or can be customized by the customer. Each harmonic violation can be mapped to its own counter or a group of harmonics can be mapped to counter or both. The system can trigger captures based on a violation as well as keeps track of the number of violations. This allows the analysis to be done in the meter reducing the amount of data that you may need to bring back. The meter can be running the IEEE-519 on current and the British Standard EN 50160 on voltage and simultaneously monitor other distorted values and non-distorted values the customer may select. The set-up of the standards is made easy using the following selection screens.

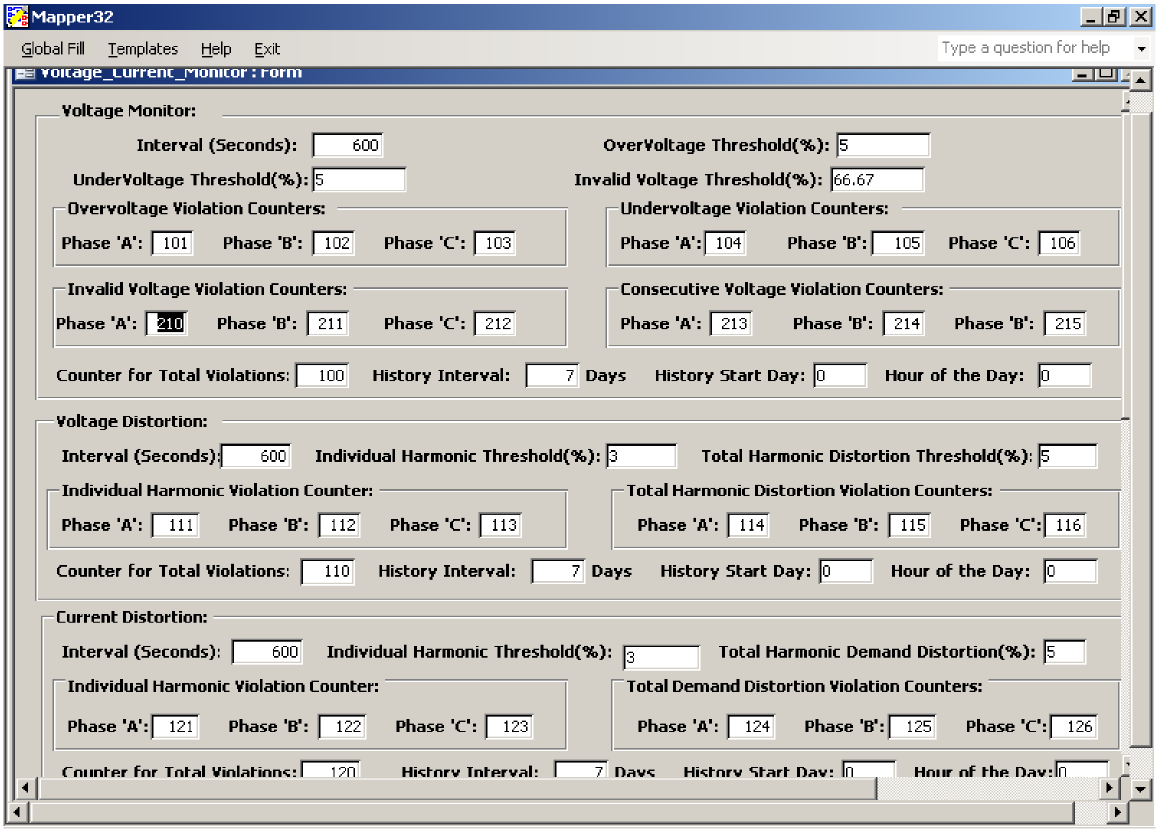
British Standard EN 50160



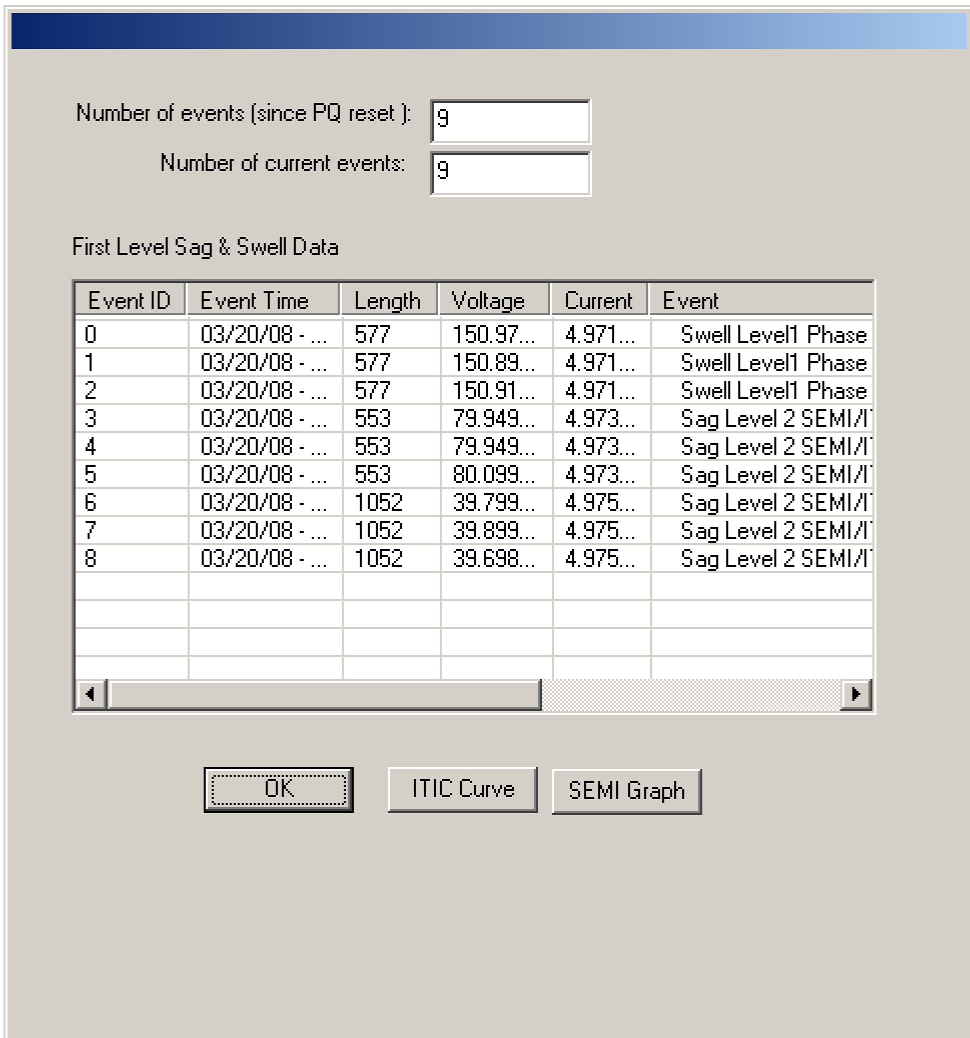
IEEE-519


Mapper32
Global Fill
Templates
Help
Exit
Type a question for help
Harmonic_Evaluation_Limits : Form
ID
Violation Counter
Threshold
0 164 3
1 163 12
2 164 3
3 163 12
4 164 3
5 163 12
6 164 3
7 163 12
Edit
Harmonic Violation Counter:
Harmonic Violation Threshold:
Update
IEEE-519 Current Distortion Tables(10-3,10-4 or 10-5):
120V Through 69KV
69KV Through 161KV
Dispersed Generation
Isc/Il Limits:
<20
20<50
50<100
100<1000
>1000
Set Defaults
OK
Version
7760

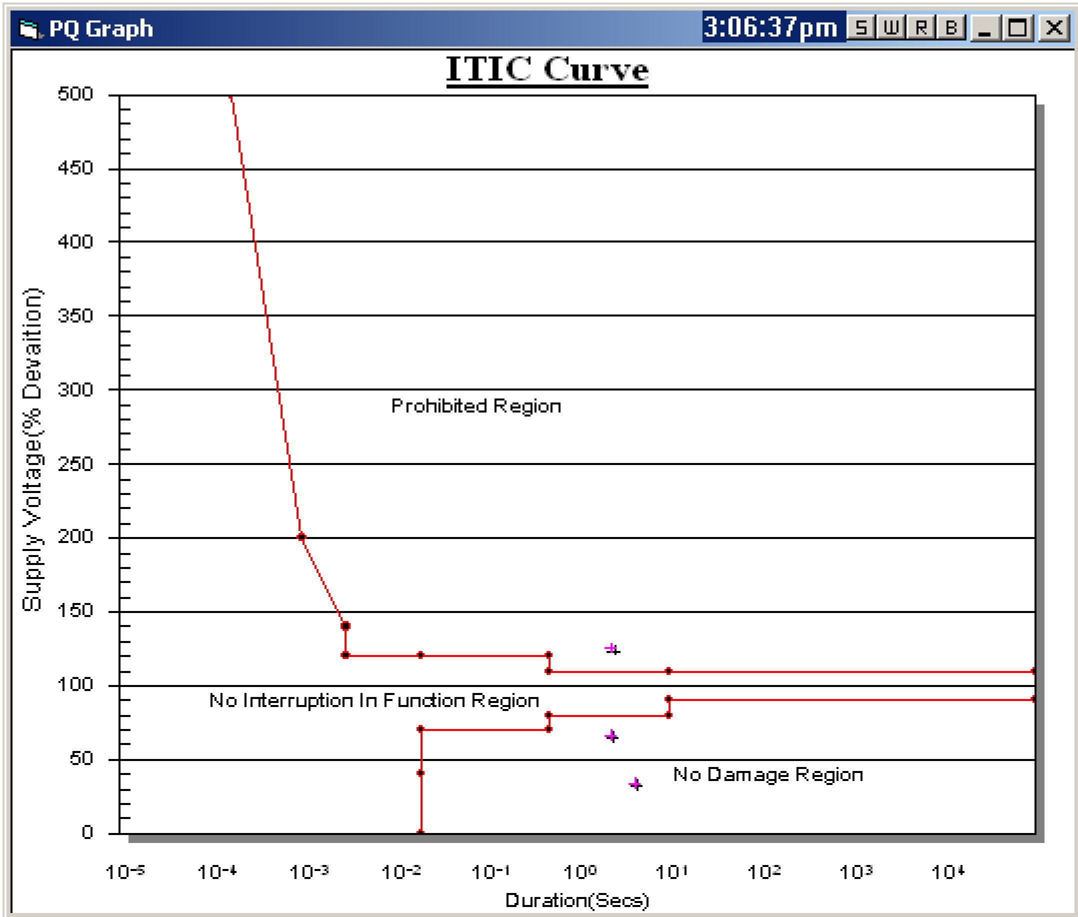
Other Distorted and Normal Monitoring parameters are set-up using the screen below.



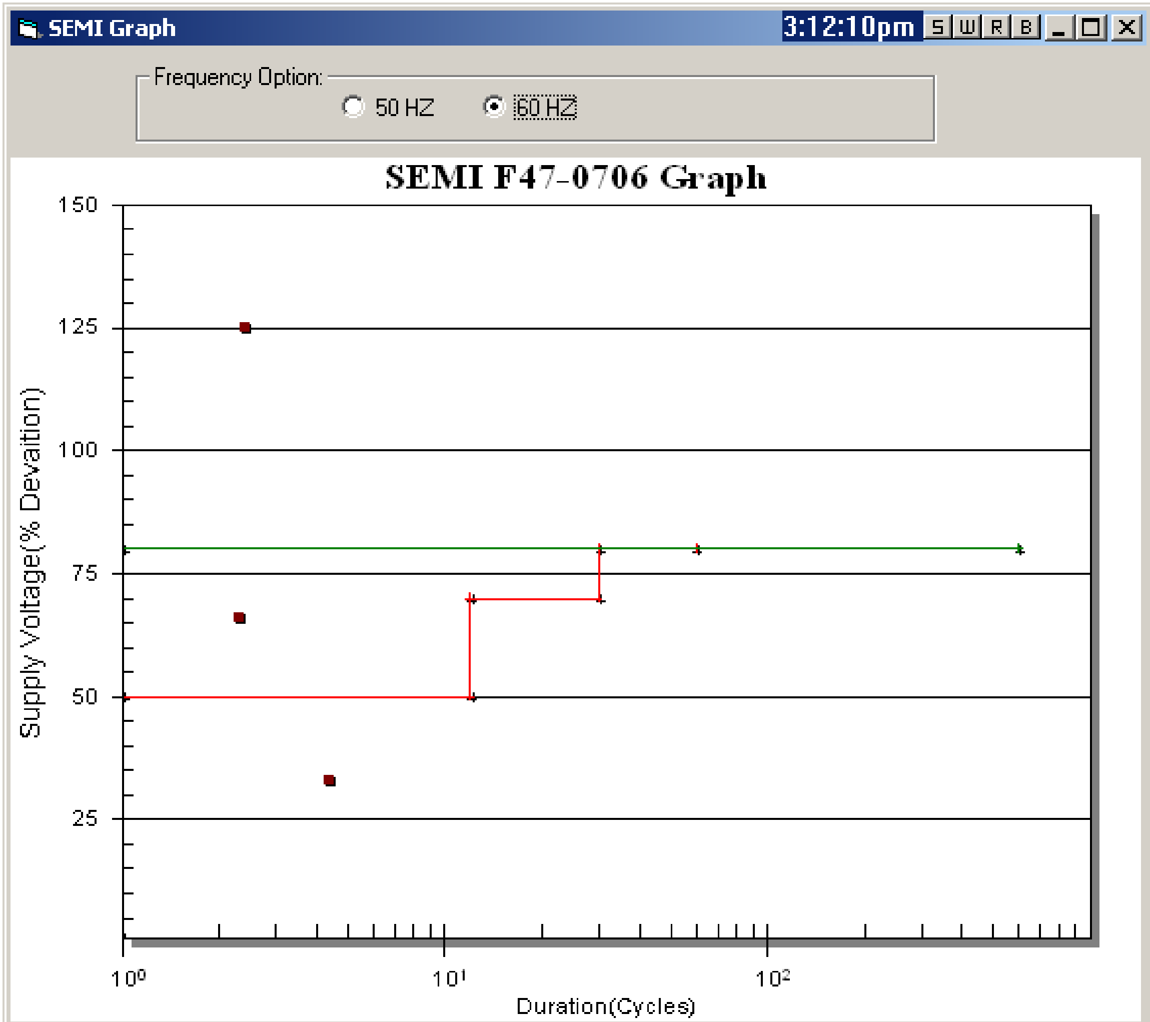
4. **Advanced Power Quality Reporting and Report by Exception**
   a. VOLTAGE SAG/SWELL ANALYSIS: The system has the ability to provide the information in three forms, Raw data, Graphs and by using Violation Counters. This would be the raw data that would be provided by MAXcom software. The reason for the event being captured is also provided along with the date and time and the duration of the event. This is the type of event information that will be supplied by the MAXcom. The data can also be exported.



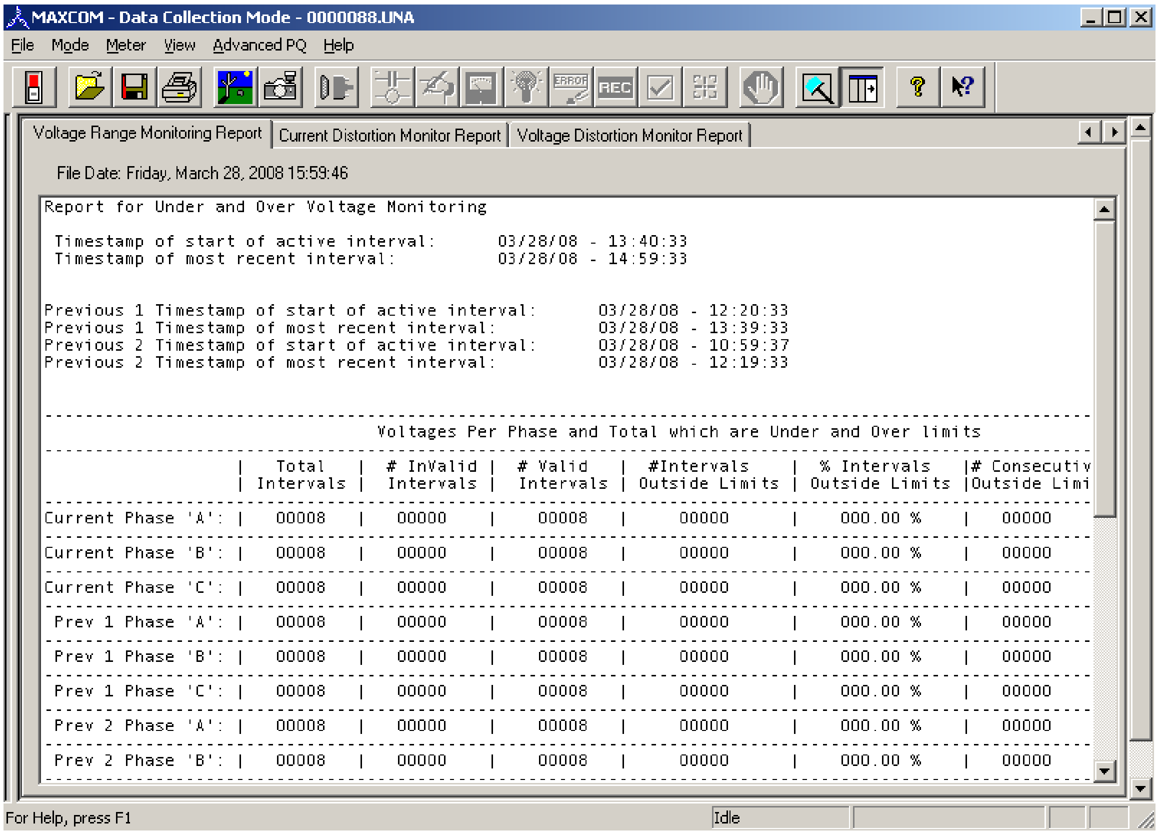
The next type of information would be Graphical. ITIC curves can be exported and imported.



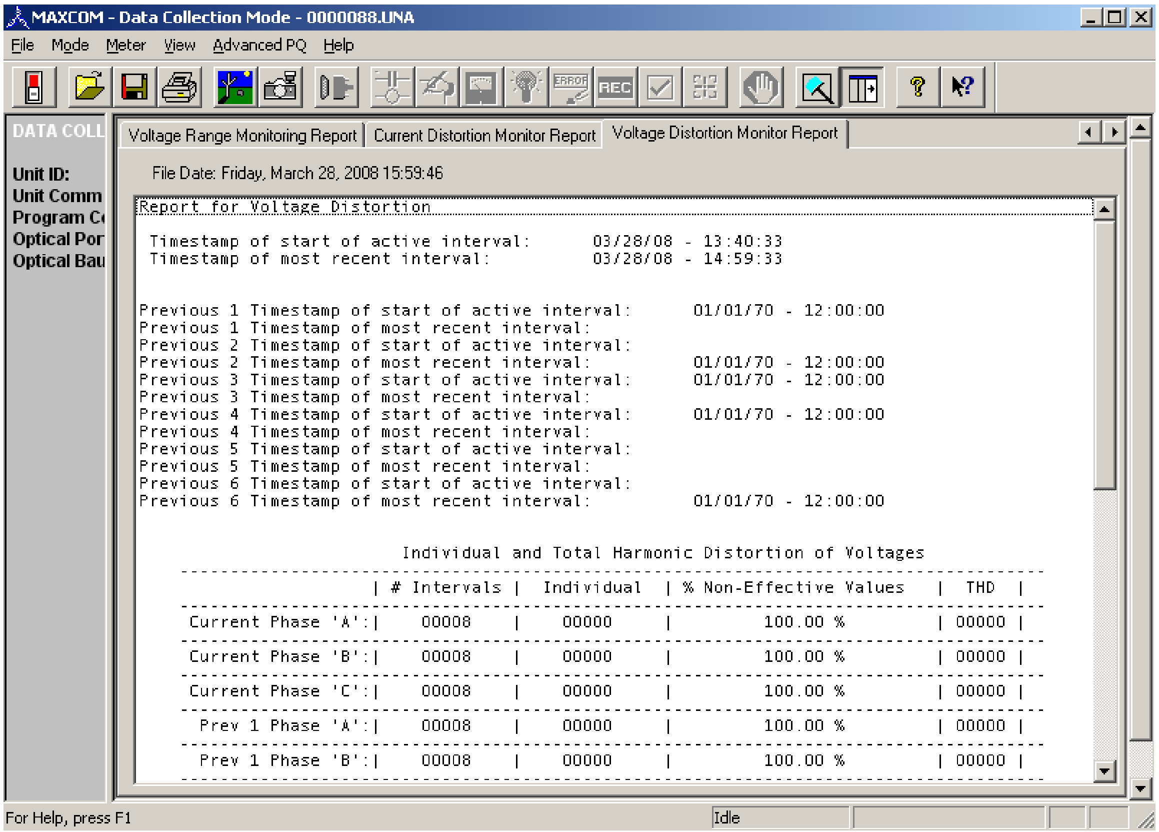
The next type of information would be Graphical. SEMI curves, the curves can be exported and imported.



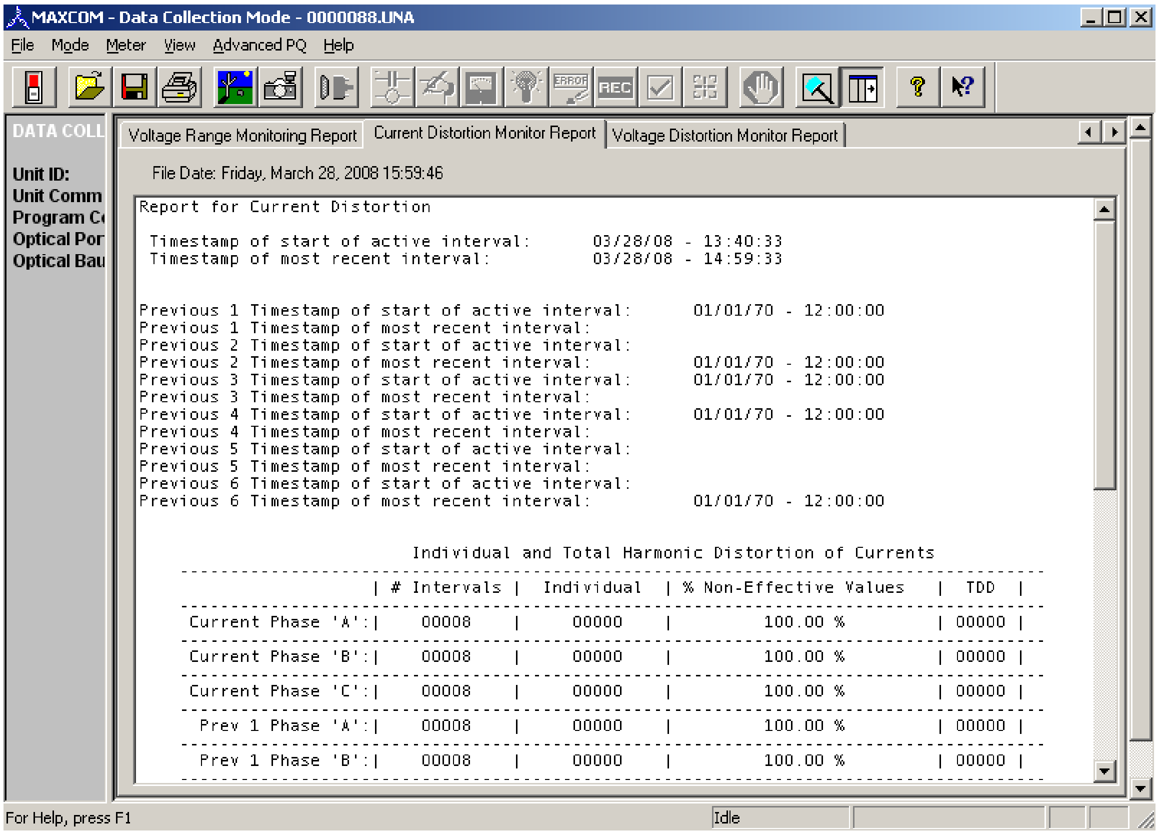
b. Normal Voltage Monitoring Information: The data is being analyzed inside of the meter and the results stored in a data table so only the results need to be brought back and displayed.



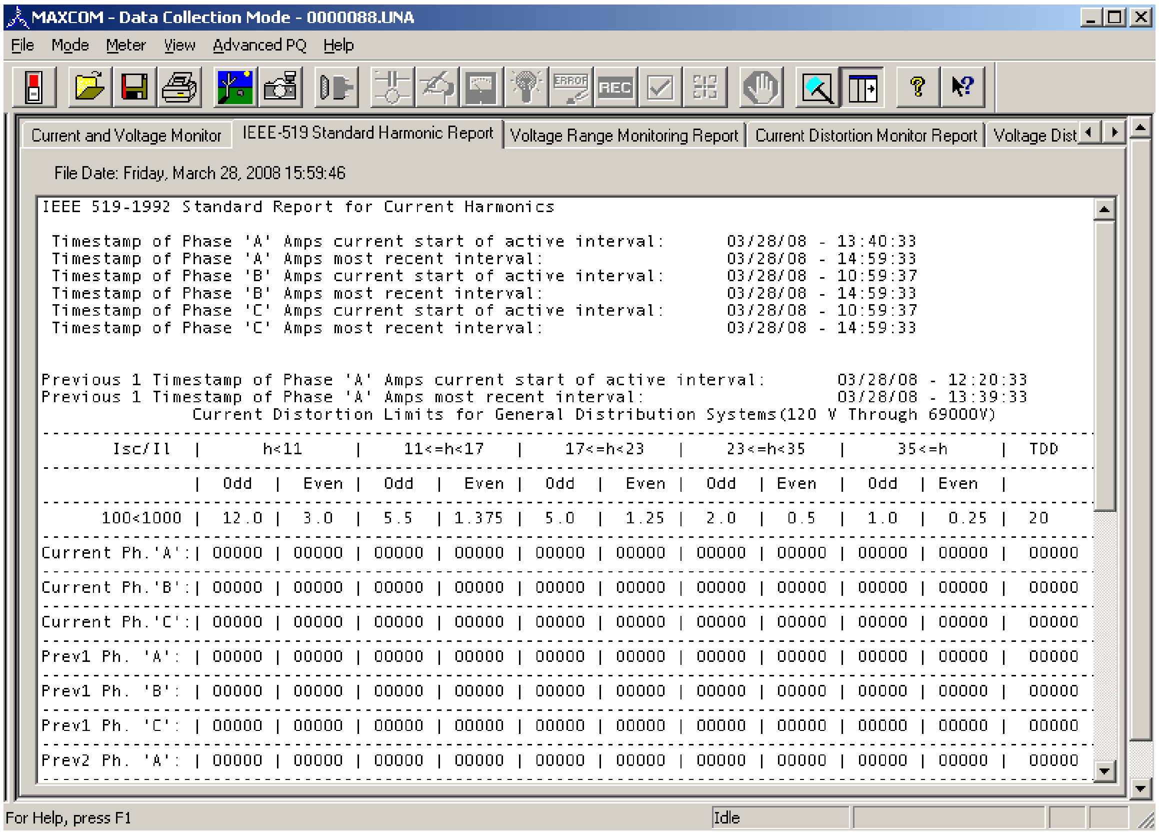
c. Distorted Voltage Report: The data is being analyzed inside of the meter and the results stored in a data table so only the results need to be brought back and displayed.



d. Distorted Current Report: The data is being analyzed inside of the meter and the results stored in a data table so only the results need to be brought back and displayed.



e. IEEE-519 Report: The data is being analyzed inside of the meter and the results stored in a data table so only the results need to be brought back and displayed.

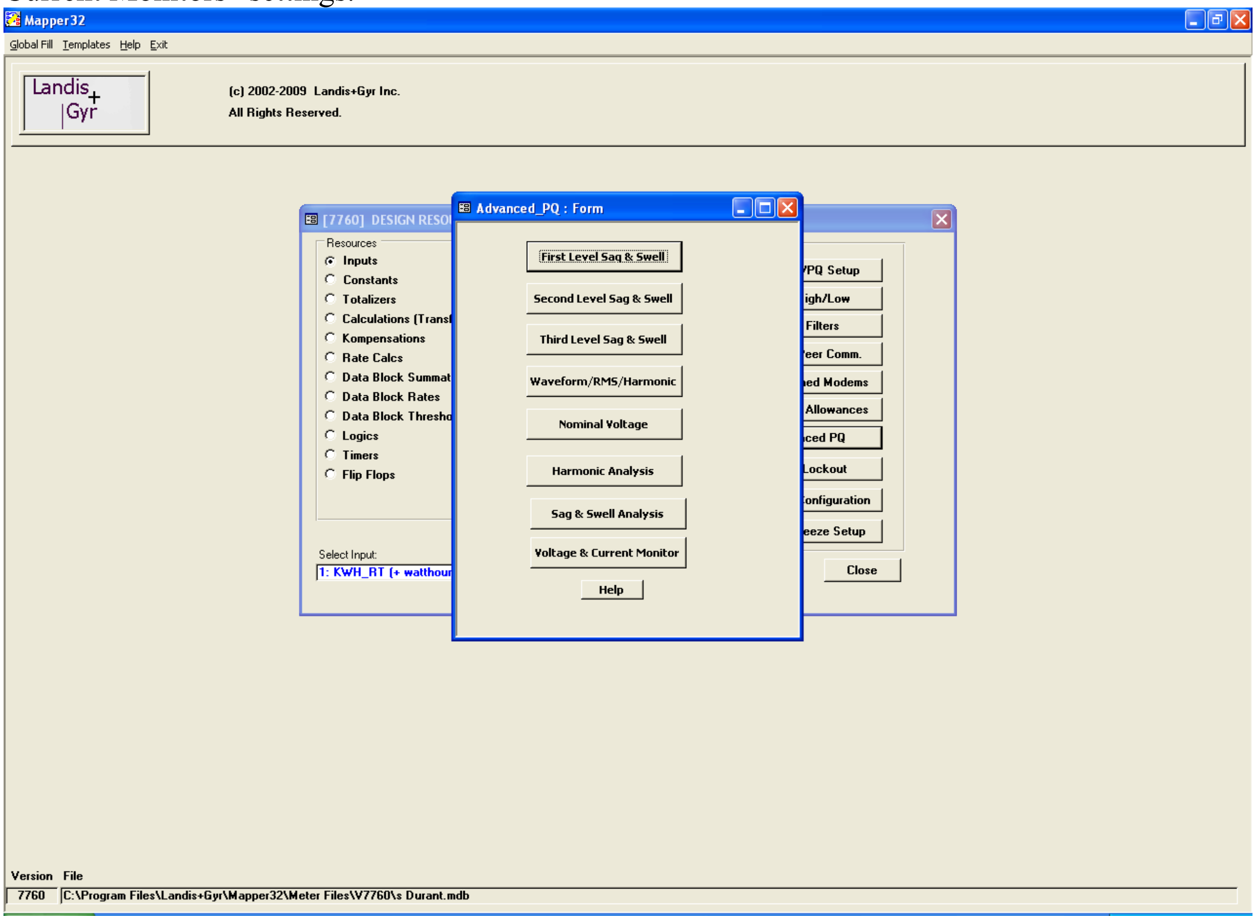


f. Other Custom Data and Reports are possible.

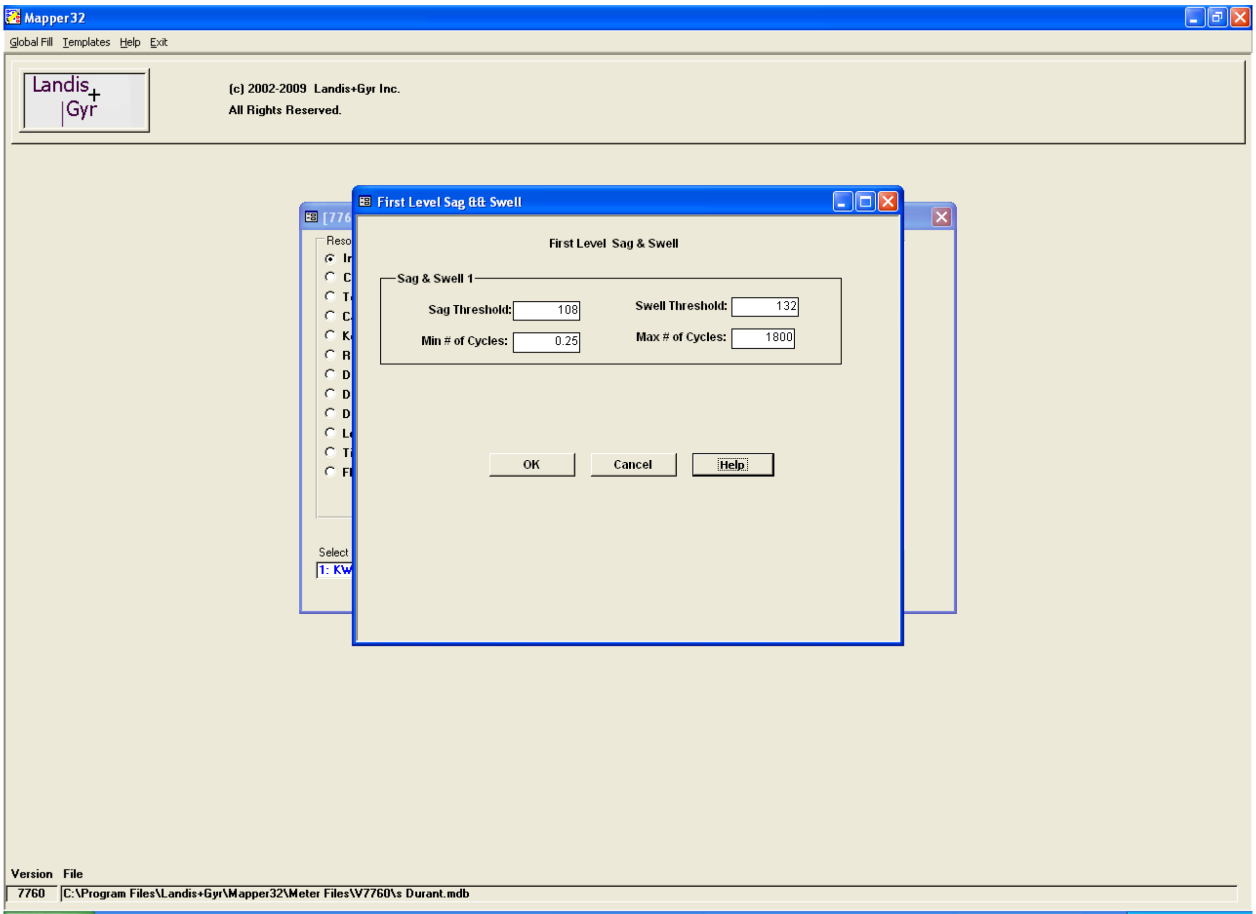
11.02.2 Advanced Power Quailty Configuration (Programming / Set-up)

Advanced PQ Set-up Process

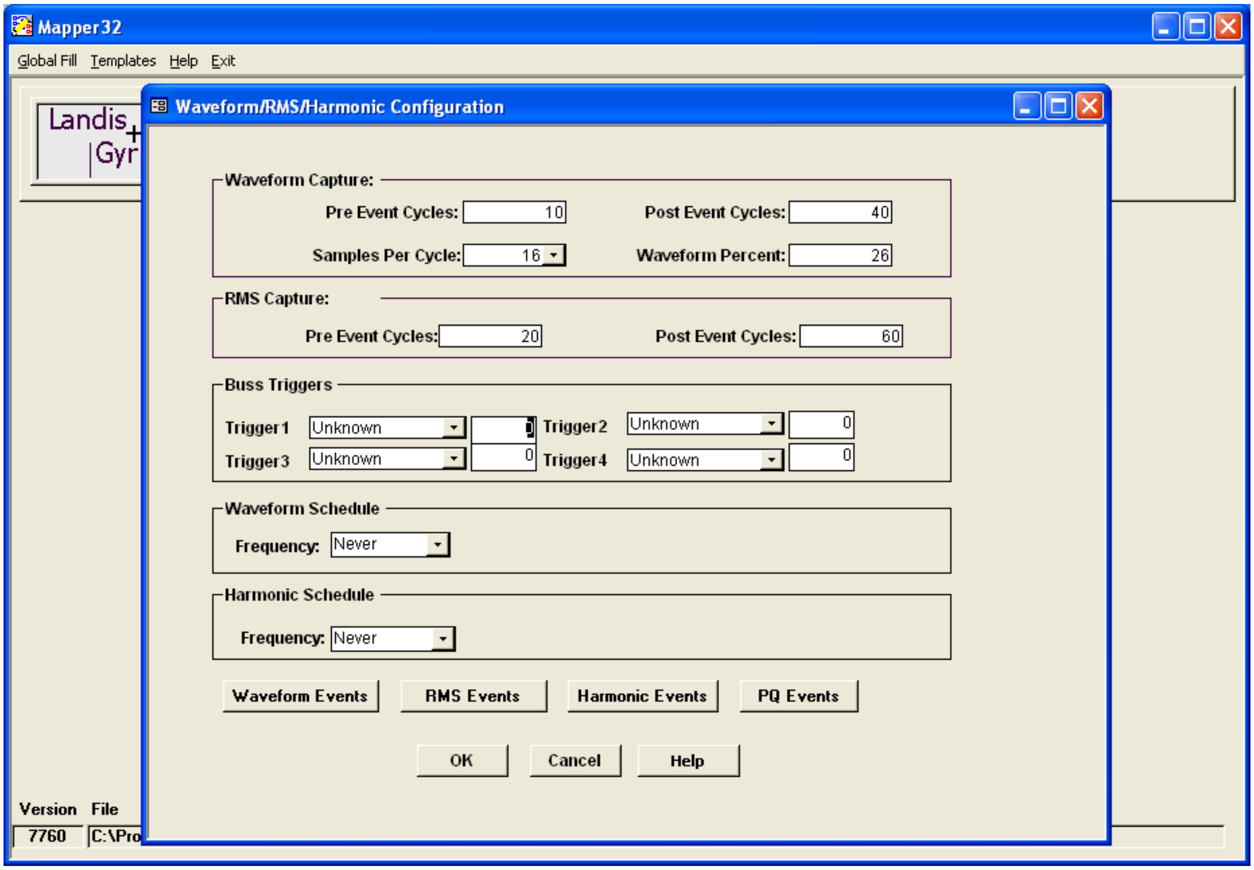
All of the advanced power quality settings have defaults, most are based on standards. The process for editing the settings would be to work down the list. Monitors and Reports will be controlled from both the “Harmonic Analysis” set-up as well as “Voltage & Current Monitors” settings.



1. Start with setting/changing the Sag and Swell Thresholds.
    a. The values will be based on the values the meter displays. If the meter display is using the "VTR" you will enter primary values. If the meter is using scaled "VTR" values then the thresholds will be scaled values. If the "VTR" is left at 1 then the values will be secondary values.
    b. Set/Edit the sag and swell limits for Sag and Swells 1-3.



2. Set-up "Waveform/RMS/Harmonic" Captures.



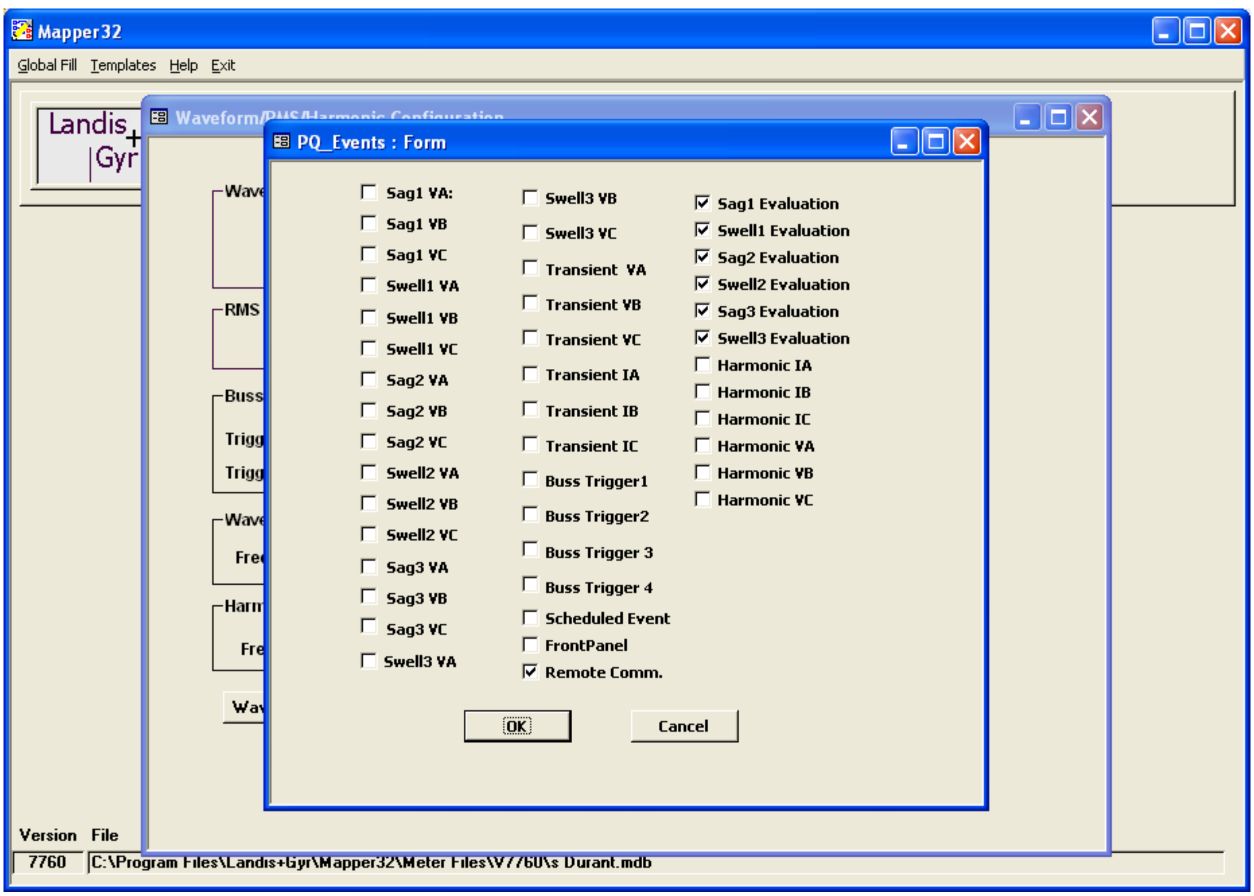
a. Waveform Captures
   i. Pre Event Cycles: 0-30 Cycles
   ii. Post Event Cycles: 0-60 Cycles
   iii. Therefore the Maximum capture cannot exceed 90 cycles. However the Maximum cannot exceed the total available which varies based on samples per cycles.
   iv. 16 Samples captures 172 cycles
   v. 32 Samples captures 86 cycles
   vi. 64 Samples captures 43 cycles
   vii. 128 Samples captures 21 cycles
   viii. 256 Samples captures 10 cycles
   i. Waveform percentage should be set at 26 % .

b. RMS Captures
   i. Pre Event Cycles: 1-600
   ii. Post Event Cycles: 1-6144

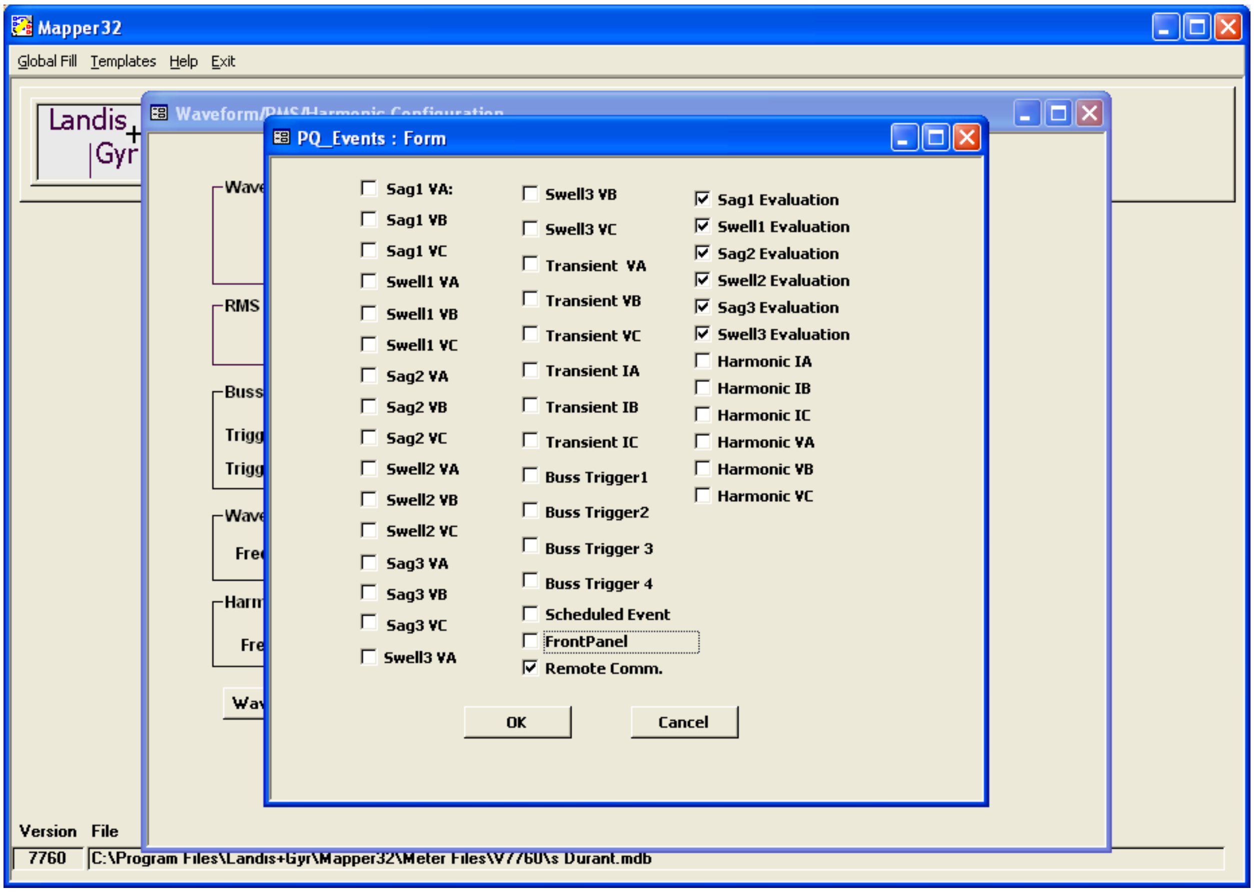
c. Buss Trigger
    i. Buss Triggers used/configured when a capture is to be done based on something other than an event. (Logic, status outputs, status inputs, etc.)

d. Waveform and Harmonic Schedules
    i. Waveform and harmonic captures can be scheduled based on time and not on events.

e. Waveform, RMS, Harmonic and PQ Events
    i. Waveform Captures: The number of unwanted captures can be controlled/limited by controlling what causes a waveform capture. The following screen shows a recommend set-up:
        1. Captures done from the front panel (buttons) of the meter will not be saved in memory.
        2. Captures can be done remotely using MAXcom or other third party software.
        3. Captures will be done when any of the Sag or Swell evaluation trigger conditions is exceeded.

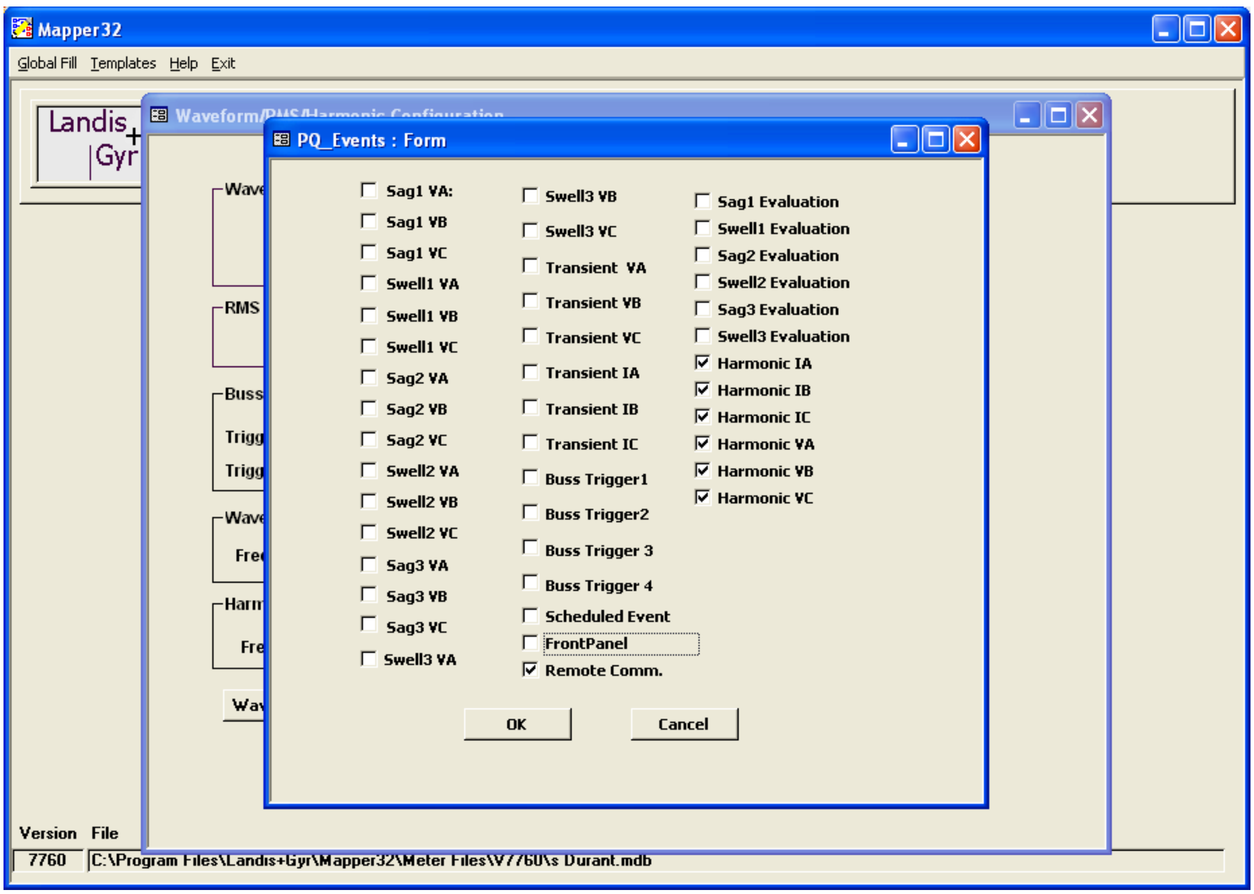


i. RMS Captures: The number of unwanted captures can be controlled/limited by controlling what causes a RMS capture. The following screen shows a recommend set-up:
   1. Captures can be done remotely using MAXcom or other third party software.
   2. Captures will be done when any of the Sag or Swell evaluation trigger conditions is exceeded.



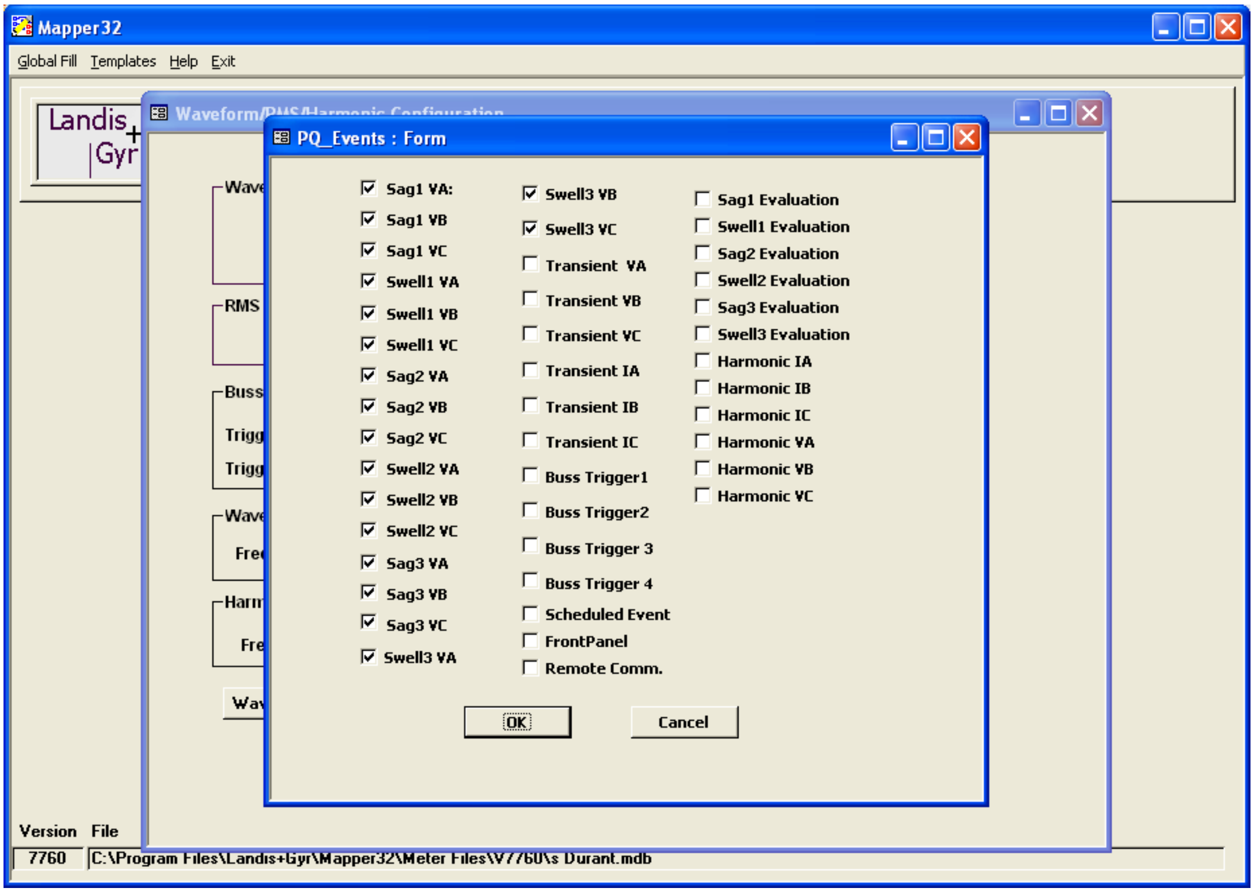
ii. Harmonic Captures: The number of unwanted captures can be controlled / limited by controlling what causes a Harmonic capture. The following screen shows a recommend set-up:

1. Captures done from the front panel (buttons) of the meter will not be saved in memory.
2. Captures can be done remotely using MAXcom or other third party software.
3. Captures will be done when any of the Harmonic evaluation trigger conditions is exceeded.

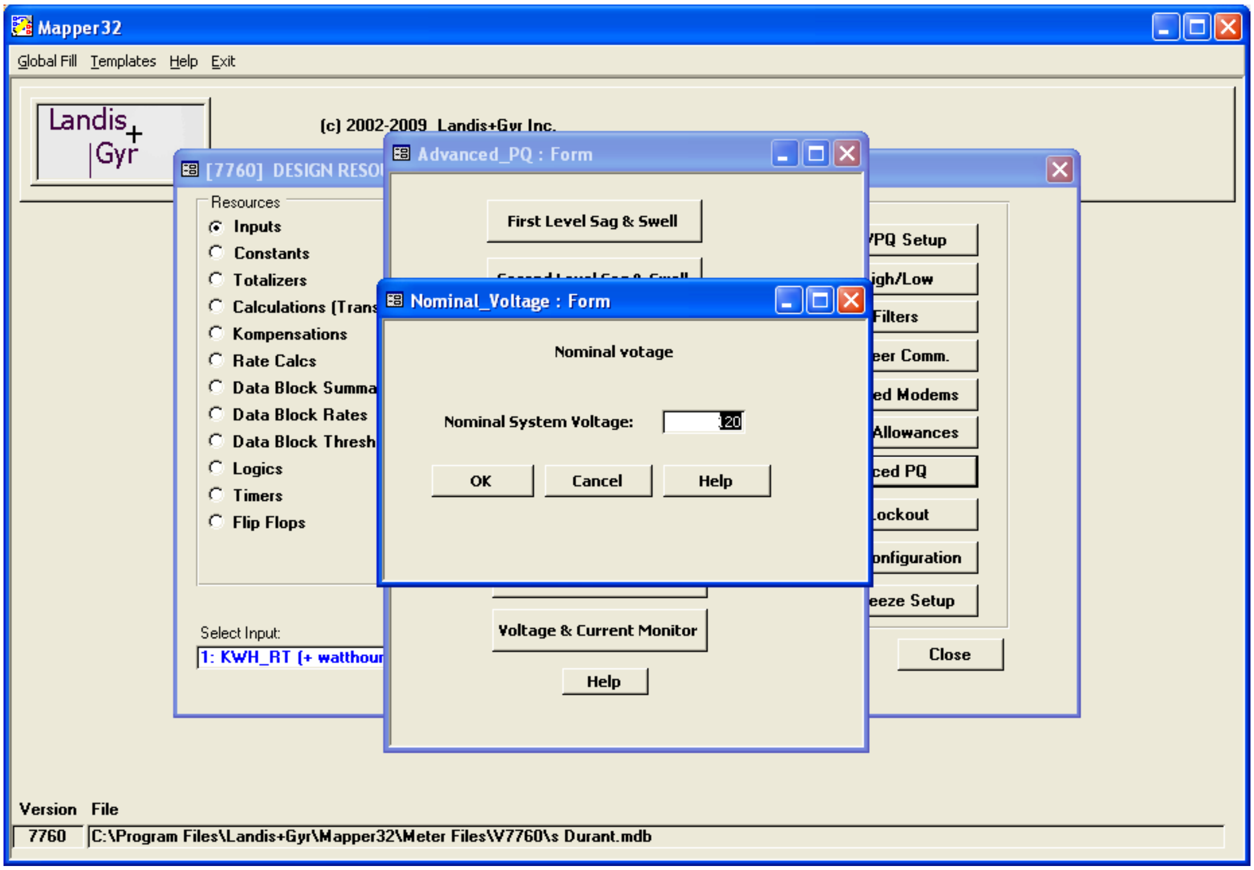


iii. PQ Events (Sag and Swell) Captures: The number of unwanted captures can be controlled / limited by controlling what causes a Harmonic capture. The following screen shows a recommend set-up:

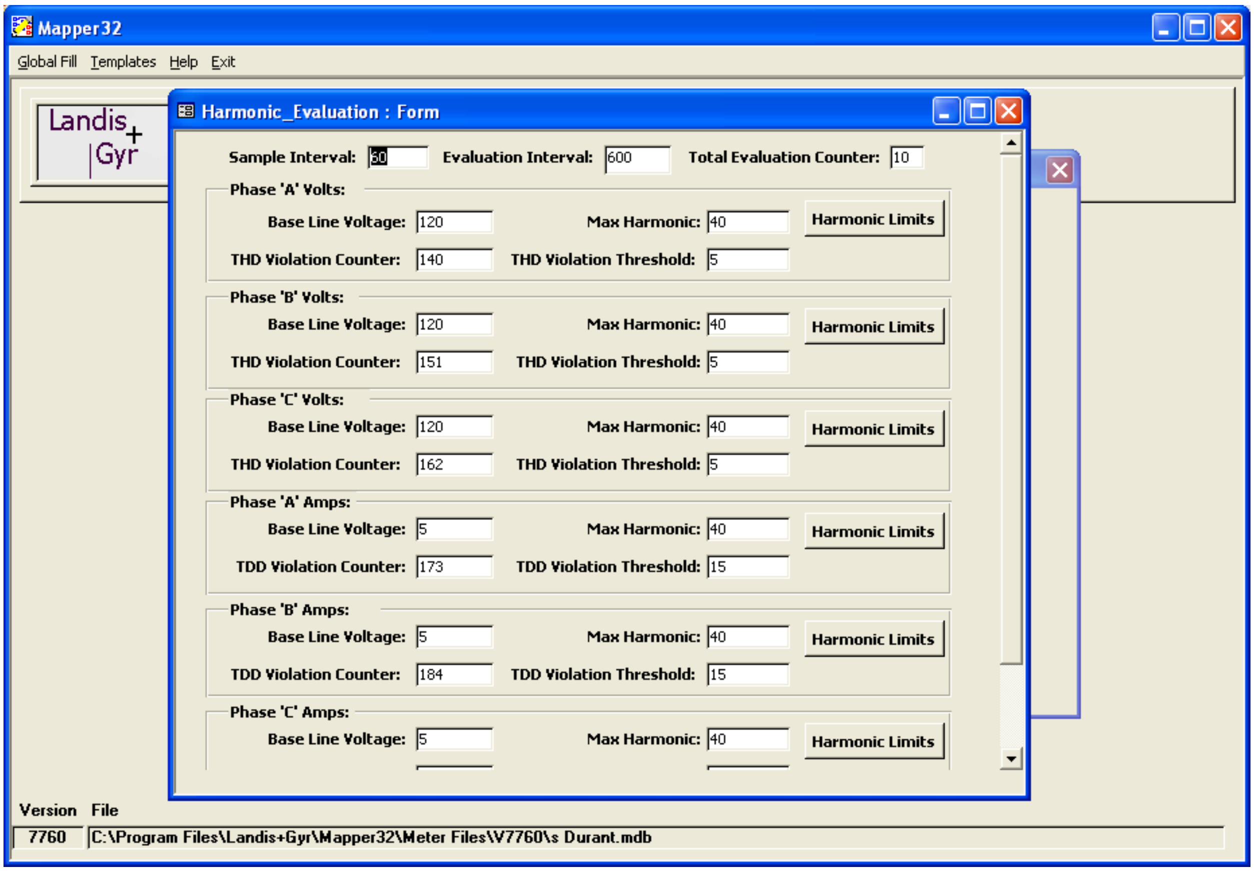
1. Captures will be done when any of the Harmonic evaluation trigger conditions is exceeded.



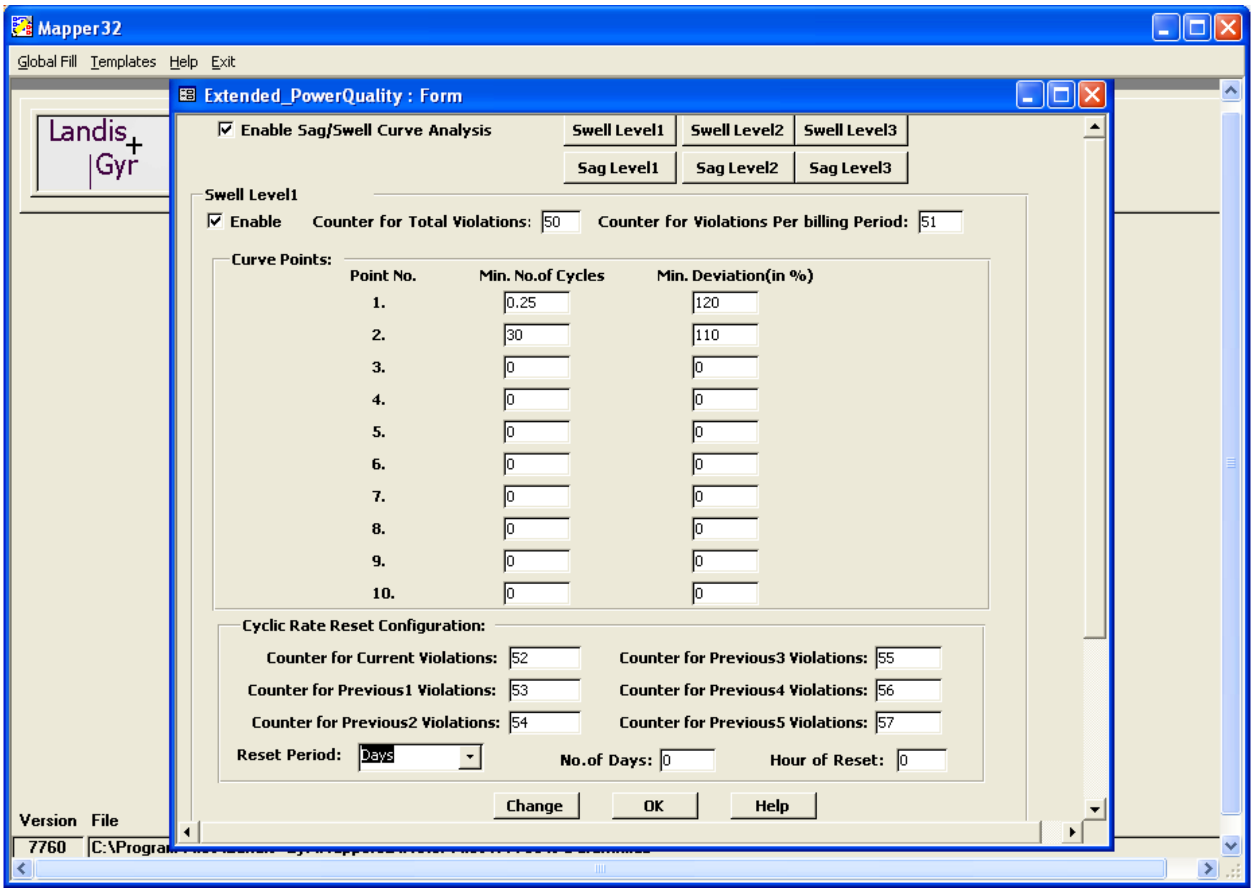
3. Nominal Voltage
    a. This value is used by the “Sag and Swell Analysis”. The values will be based on the values the meter displays. If the meter display is using the “VTR” you will enter primary values. If the meter is using scaled “VTR” values then the thresholds will be scaled values. If the “VTR” is left at 1 then the values will be secondary values.



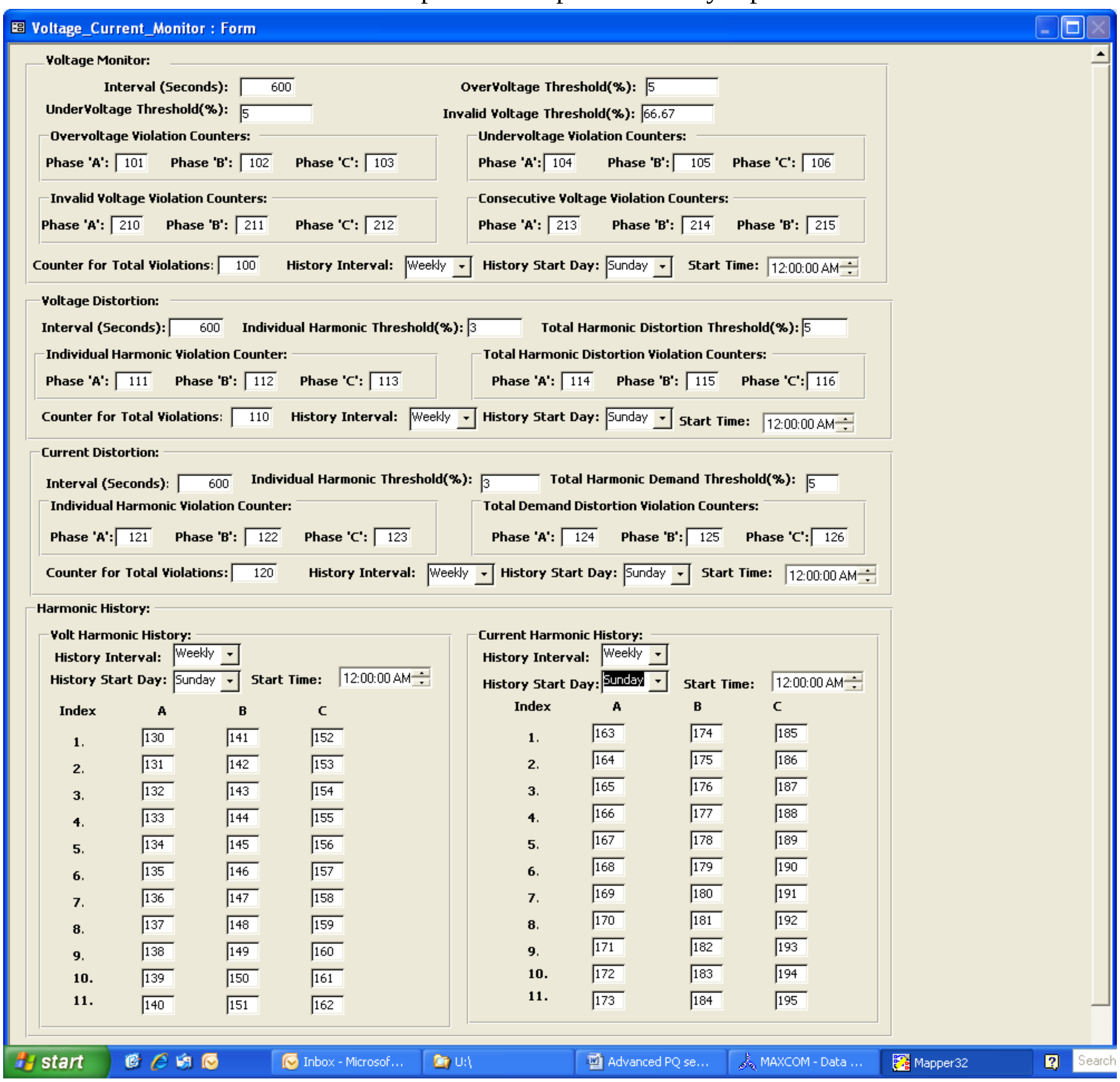
4. Harmonic Analysis
    a. The following values are also used by the "Distorted Monitor & Reports".
        i. Sample Intervals
        ii. Base Line Voltages
        iii. Base Line Current
        iv. Max Harmonics
    b. The Harmonic Limits are based on
        i. Current – IEEE 519
        ii. Voltage – BS EN 50160



5. Sag and Swell Analysis
   a. Each of the Sag and Swell (Analysis) Level1-3 will be used to evaluate every Sag or Swell.
      i. Sag and Swell Level 1 have been set based on CEBMA/ITIC.
      ii. Sag and Swell Level 2 have been set based on SEMI (Required)
      iii. Sag and Swell Level 3 have been set based on SEMI (Suggested)



6. Voltage and Current Monitors and Harmonic History
    a. Voltage Monitor
        i. Interval (Evaluation): Must be a multiple of the “Sample Interval” from the Harmonic Analysis set-up.
        ii. Over Voltage Threshold: The percentage is calculated on the “Base Line” from the Harmonic Analysis set-up.
        iii. Under Voltage Threshold: The percentage is calculated on the “Base Line” from the Harmonic Analysis set-up.
        iv. Invalid Voltage Threshold: The percentage is calculated on the “Base Line” from the Harmonic Analysis set-up. (66.67=40).
        v. It is suggested the default violation counters not be changed.
        vi. The default report is set-up for a weekly report.



b. Voltage Distortion Monitor
    i. Interval (Evaluation): Must be a multiple of the "Sample Interval" from the Harmonic Analysis set-up.
    ii. Individual Harmonic Thresholds: The percentage is calculated on the "Base Line" from the Harmonic Analysis set-up.
    iii. Total Harmonic Distortion Threshold: The percentage is calculated on the "Base Line" from the Harmonic Analysis set-up.
    iv. It is suggested the default violation counters not be changed.
    v. The default report is set-up for a weekly report.

c. Current Distortion Monitor
    i. Interval (Evaluation): Must be a multiple of the "Sample Interval" from the Harmonic Analysis set-up.
    ii. Individual Harmonic Thresholds: The percentage is calculated on the "Base Line" from the Harmonic Analysis set-up.
    iii. Total Harmonic Demand Threshold: The percentage is calculated on the "Base Line" from the Harmonic Analysis set-up.
    iv. It is suggested the default violation counters not be changed.
    v. The default report is set-up for a weekly report.

d. Harmonic History
    i. It is suggested the default violation counters not be changed.
    ii. The default report is set-up for a weekly report.

11.03.1 Form 36 Meters

Understanding Form 6 and 36 Meters

The forms 6 and 36 meters are known as "Z" coil meters and 2 ½ element meters. The meter was used where saving the cost of the third PT out-weights the need for accuracy. In the electro-mechanical meter there are two potential coils and four current coils (2 of the current coils are used by the "B" phase current circuit). The results in a three phase circuit at unity power fact is W= (Wa = (Va x Ia) + (Wb=(Va x Ib x .5) +(Vc x Ib x .5)) + (Wc= (Vc x Ic))). The reason for the one half (0.5) in the "B" phase calculation is the current and the voltages are displaced by 60 degrees. The 60 degrees displacement is only present in a three phase circuit and watts will equal Volts x Amps x 3 x PF. However when testing or running the meter single phase (series), the 60 degree displacement is not present causing all of the voltages and currents to be in phase, therefore watts will equal Volts x Amps x 4 x PF. When you applied 120 volts and 5 amps with the meter connected 3-phase the meter would read 1800 watts or 1.8 Kw, however if the same meter was connect series (single-phase) the meter would register 2400 watts or 2.4 Kw. This is why with the same load applies you will get a deferent percentage depending on the how you run the test (single or three phase). This will cause your full load test point (watts) to be different in single and 3-phase testing with the same load applied.

Understanding the Form 36 Elite Meters

The form 36 meter is call a “Z” coil meters or a 2 ½ element meters. The meter is used where saving the cost of the third PT out-weights the need for accuracy. In the Elite meter there are two potential coils and three current coils. However the Elite meter does a vector calculation to arrive at a “B” phase voltage. The results in a three phase circuit at unity power fact is W= (Wa = (Va x Ia) + (Wb = (Vb x Ib) + (Wc = (Vc x Ic))). The watts will equal Volts x Amps x 3 x PF in a 3-phase circuit. However when testing or running the meter single phase (series), the 120 degree displacement between the voltages go to zero degrees, they are all in phase with each other. This will cause the “B” phase voltage calculation to be equal to the sum of “A” and “B” phase voltages. Therefore with 2-times the voltage on “B” phase the watts will still equal Volts x Amps x 4 x PF. Therefore if you applied 120 volts and 5 amps with the meter connected 3-phase the meter would read 1800 watts or 1.8 Kw, however if the same meter was connect series (single-phase) the meter would register 2400 watts or 2.4 Kw. This is why with the same load applies you will get a deferent percentage depending on the how you run the test (single or three phase). This will cause your full load test point (watts) to be different in single and 3-phase testing with the same load applied.

Understanding TLC in Form 6 and 36 Meters

Power transformer losses are calculated based on the phase voltages and phase currents in the meters. The losses are then compared to the measured power to arrive at the percent losses. Therefore the voltage, current and power measurements will all play a part in controlling the percent losses. When the measured voltages and the currents in the meter are the same for both single or 3-phase testing, the losses will be the same in both tests (lets say the looses are 10). The next question is, does the power measurement in both single and 3-phase testing with the same load applied, provide the same results. Based on the information above we know in a form 6 or 36 meter the results for power (watts) will be different between single and 3-phase testing. Using the power numbers (Watts) from the above, when the meter is tested 3-phase the percent losses will be 10/1800 or 0.55 %. If the meter is tested series (single phase) the percent losses will be 10/2400 or 0.416 %. This is the reasons for a 3-phase and single phase TLC test sheet.

Understanding TLC in Form 36 Elite Meters

Power transformer losses are calculated based on the phase voltages and phase currents in the meters. The losses are then compared to the measured power to arrive at the percent losses. Therefore the voltage, current and power measurements will all play a part in controlling the percent losses. Because the voltages the values will not be the same in the Elite meter when testing single and 3-phase, the losses will not be the same in both tests. This is because when testing or running the meter single phase (series), the 120 degree displacement between the voltages go to zero degrees, they are all in phase with each other. This will cause the "B" phase voltage calculation to be equal to the sum of "A" and "B" phase voltages (double the value in 3-phase). With double the voltage on "B" phase the total "Iron" losses in series testing will be double the value in three phase testing. Based on this information (lets say the losses are 10 for 3-phase and 12 for single phase tests). The next question is does the power measurement in both single and 3-phase testing with the same load applied provide the same results. Based on the information above we know in a form 6 or 36 meter the results for power (watts) will be different between single and 3-phase testing. Using the numbers from the above when the meter is tested 3-phase the percent losses will be 10/1800 or 0.55 %. When the Elite meter is series tested because of the vector calculation for "B" voltage the percent losses will be 12/2400 or 0.50 %. This is the reasons for a 3-phase and single phase TLC test sheet.

Entering TLC Data into the Elite Meter

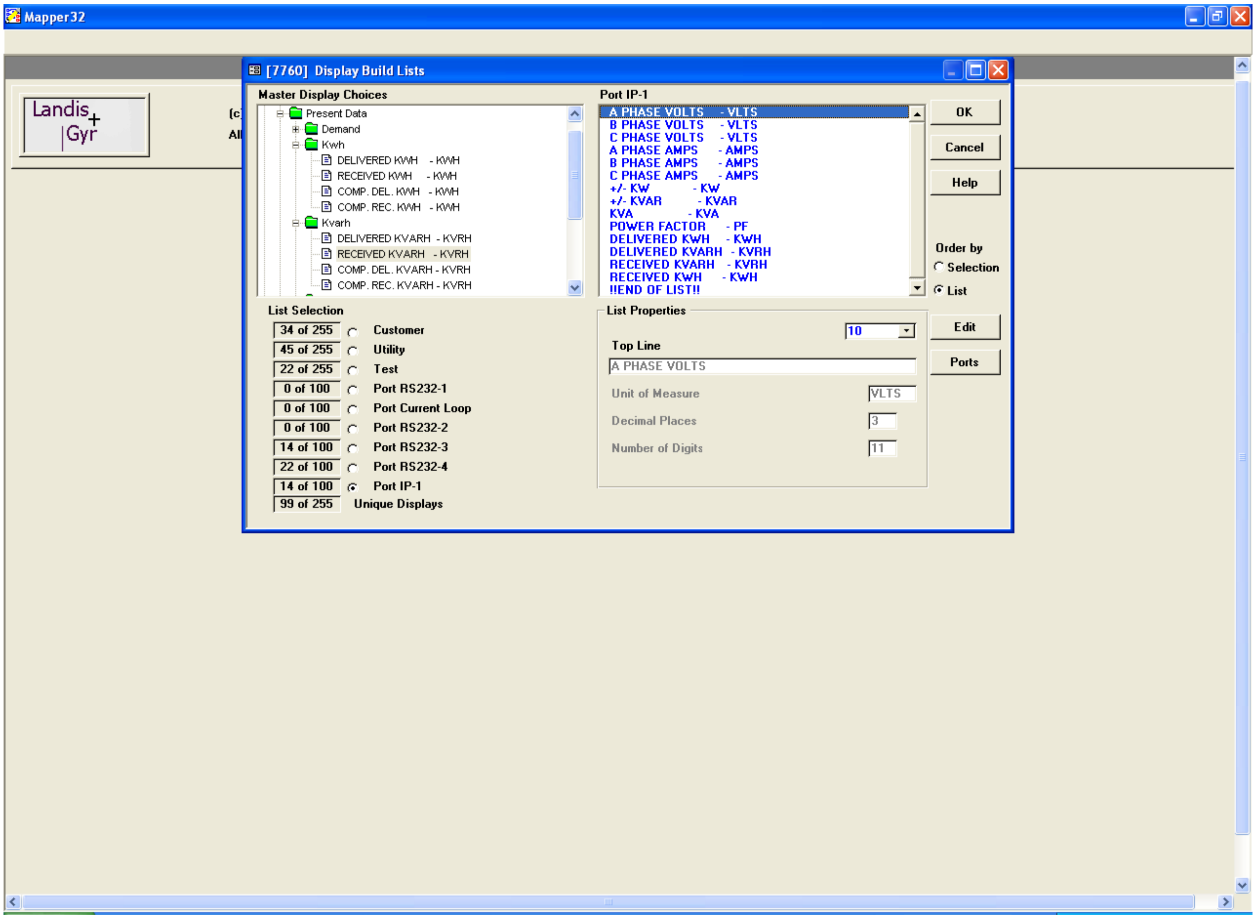
Transformer loss information is entered into the meter using MAXcom. MAXcom will take the information and calculate the copper and iron values that the needs and loads them into the Elite meter. The information can be provided to MAXcom using "Transformer Loss Calculations" (information from the transformer data sheet) which is recommended or using "Transformer Loss Coefficients" (percent losses) which requires the percentages to be base on 3-phase test results, NOTE single results.

11.04.1 DNP Over-IP Set-up

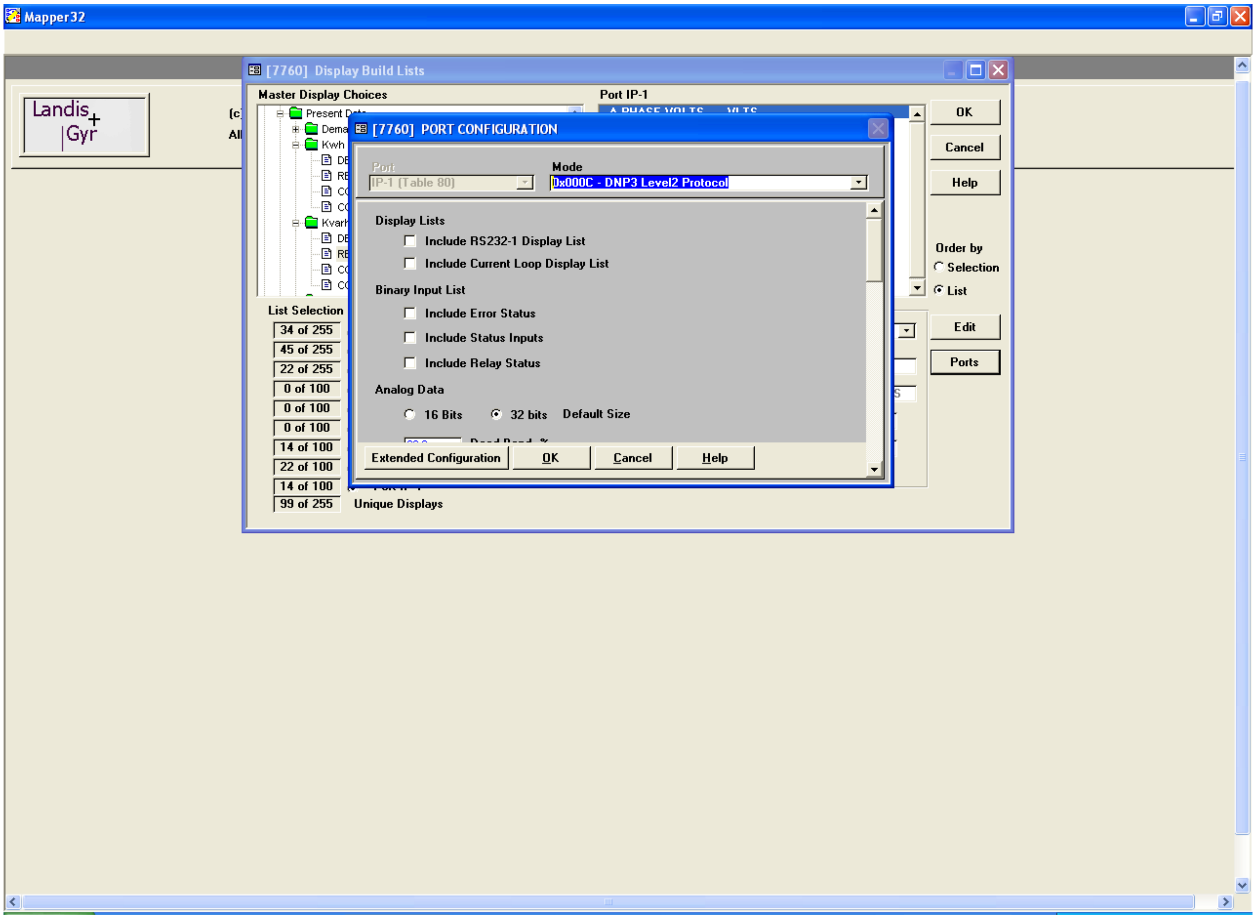
I used the following process to set-up DNP over Ethernet.

Step1.

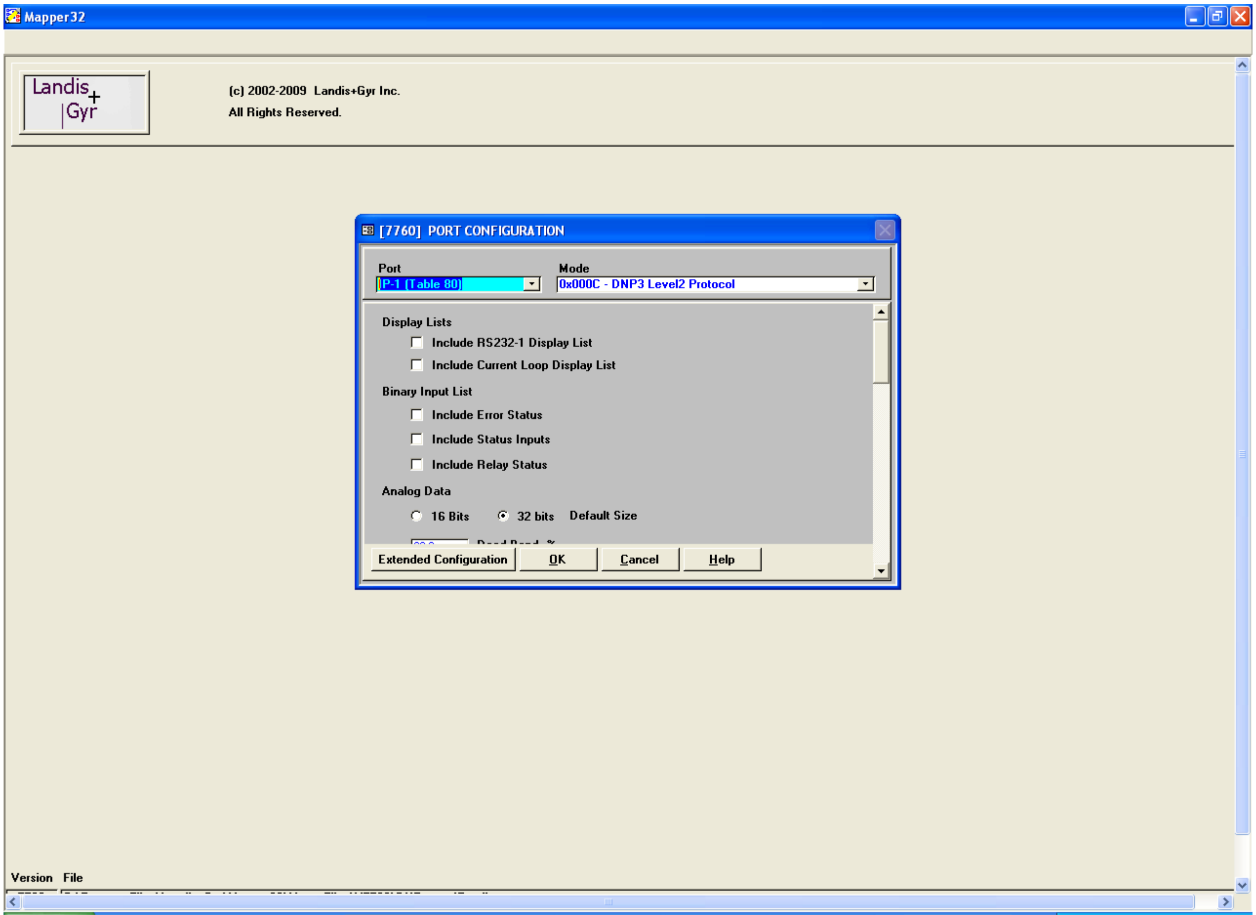
a. Run mapper32
b. Make a file (I used Meter File as a template.
c. Select; Program from the menu
    a. Displays
        i. Select; Port IP-1
            1. Select the items to be sent to the DNP RTU running in the meter. This example has 14 items. Three voltages Scaled by 10), three currents (scaled by 100), Kw (scaled by 10), Kvar (scaled by 10), Kva Power Factor (scaled by 100), Kwh Delivered (scaled by 10), Kvarh Delivered (scaled by 10), Kvarh Received (scaled by 10) and Kwh Received (scaled by 10).
            2. Click on ports (see next page)


Mapper32
[7760] Display Build Lists
Master Display Choices
Present Data
Demand
Kwh
DELIVERED KWH - KWH
RECEIVED KWH - KWH
COMP. DEL. KWH - KWH
COMP. REC. KWH - KWH
Kvarh
DELIVERED KVARH - KVRH
RECEIVED KVARH - KVRH
COMP. DEL. KVARH - KVRH
COMP. REC. KVARH - KVRH
Port IP-1
A PHASE VOLTS - VLTS
B PHASE VOLTS - VLTS
C PHASE VOLTS - VLTS
A PHASE AMPS - AMPS
B PHASE AMPS - AMPS
C PHASE AMPS - AMPS
+/- KW - KW
+/- KVAR - KVAR
KVA - KVA
POWER FACTOR - PF
DELIVERED KWH - KWH
DELIVERED KVARH - KVRH
RECEIVED KVARH - KVRH
RECEIVED KWH - KWH
!!END OF LIST!!
OK
Cancel
Help
Order by
Selection
List
List Selection
34 of 255 Customer
45 of 255 Utility
22 of 255 Test
0 of 100 Port RS232-1
0 of 100 Port Current Loop
0 of 100 Port RS232-2
14 of 100 Port RS232-3
22 of 100 Port RS232-4
14 of 100 Port IP-1
99 of 255 Unique Displays
List Properties
10
Top Line
A PHASE VOLTS
Unit of Measure VLTS
Decimal Places 3
Number of Digits 11
Edit
Ports

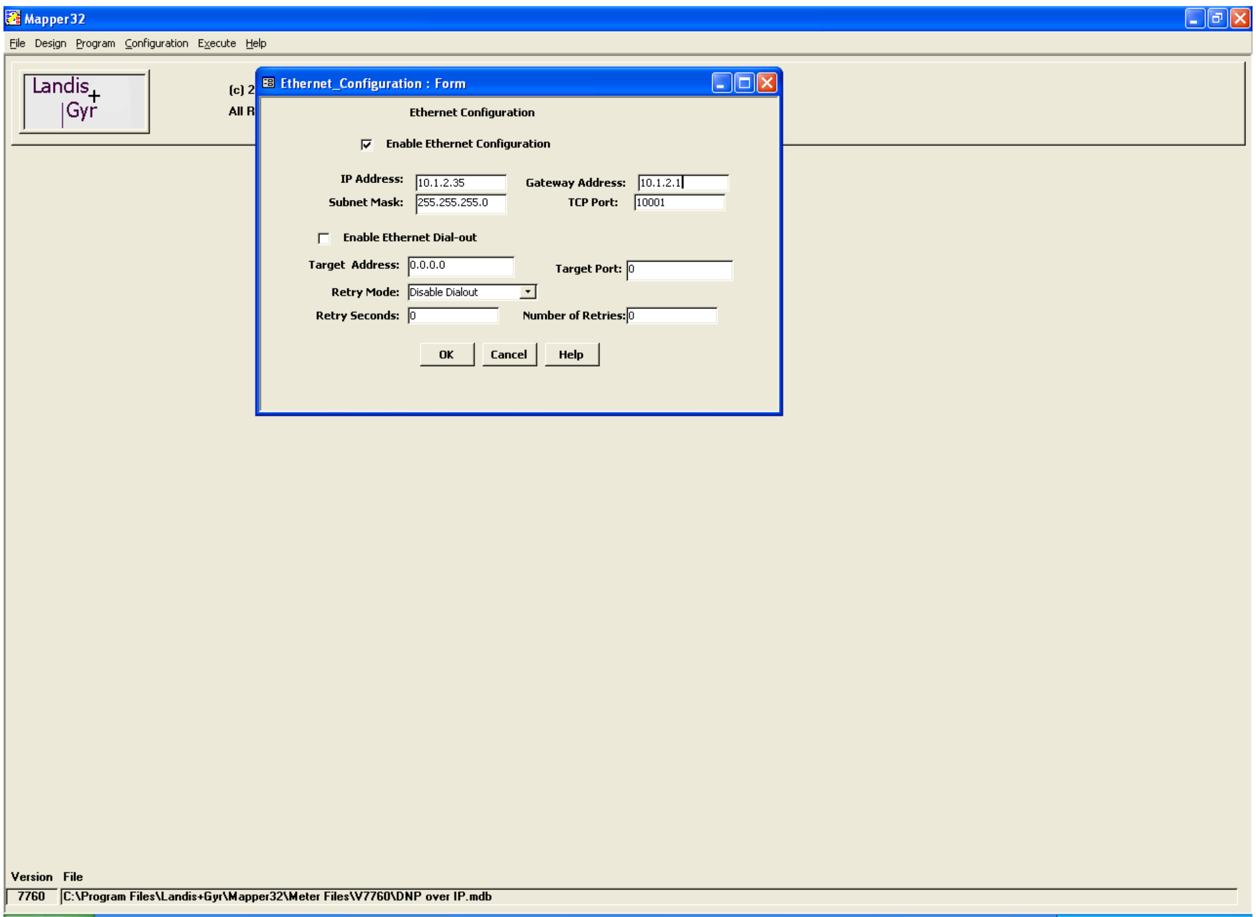
3. This screen will allow you to select DNP level 2 and configure the DNP set-up. After completing you set-up return to the program screen and select ports.



4. Check all of the ports and make sure only one port has been configured for DNP. In this example only the IP port has been configured as a DNP port.
5. Return to the program screen.

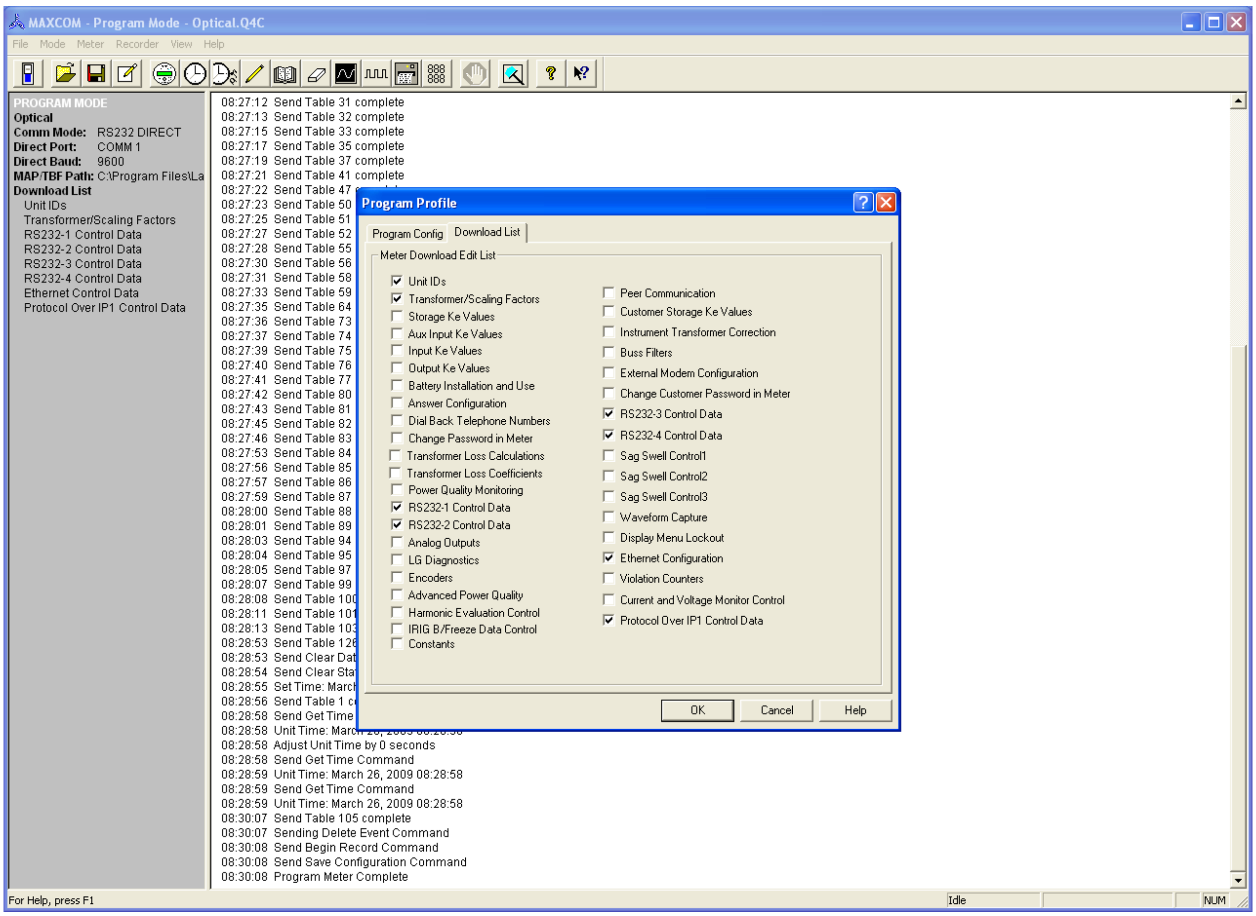


6. Select Ethernet Configuration and configure the IP Address, Mask, gateway and port (this information will be provided by your IT department). You can enter or change this information when programming the meter within MAXcom.
7. Save as "tbf" file.



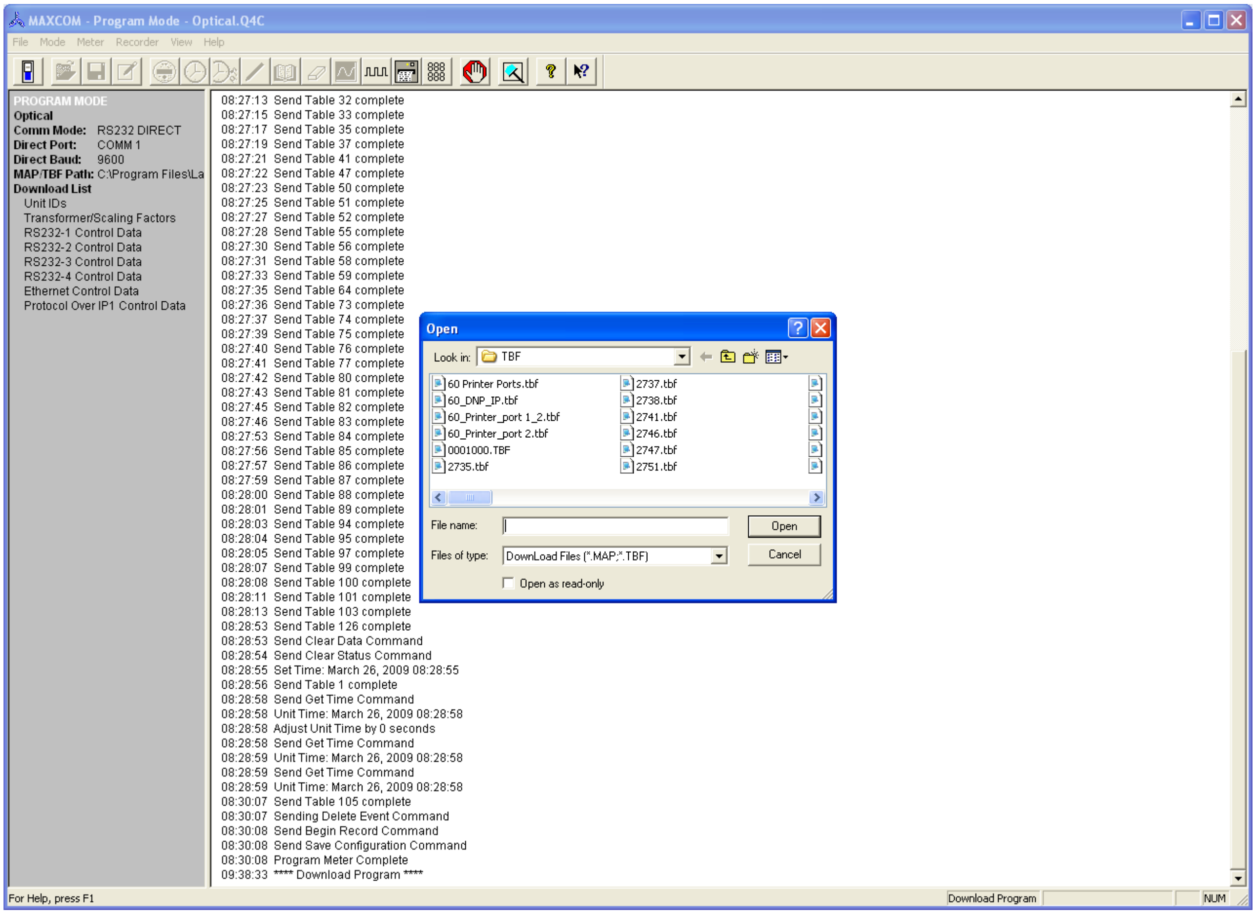
Step2.

a. Run MAXcom
b. Go to the "Program" Mode
c. Edit "Program Profile"
    a. Download List should include
        i. All RS232 ports
        ii. Ethernet Configuration
        iii. Protocol over IP
        iv. Return to Program Mode screen
d. Connect to meter Optically or RS232
e. Select Program Meter.

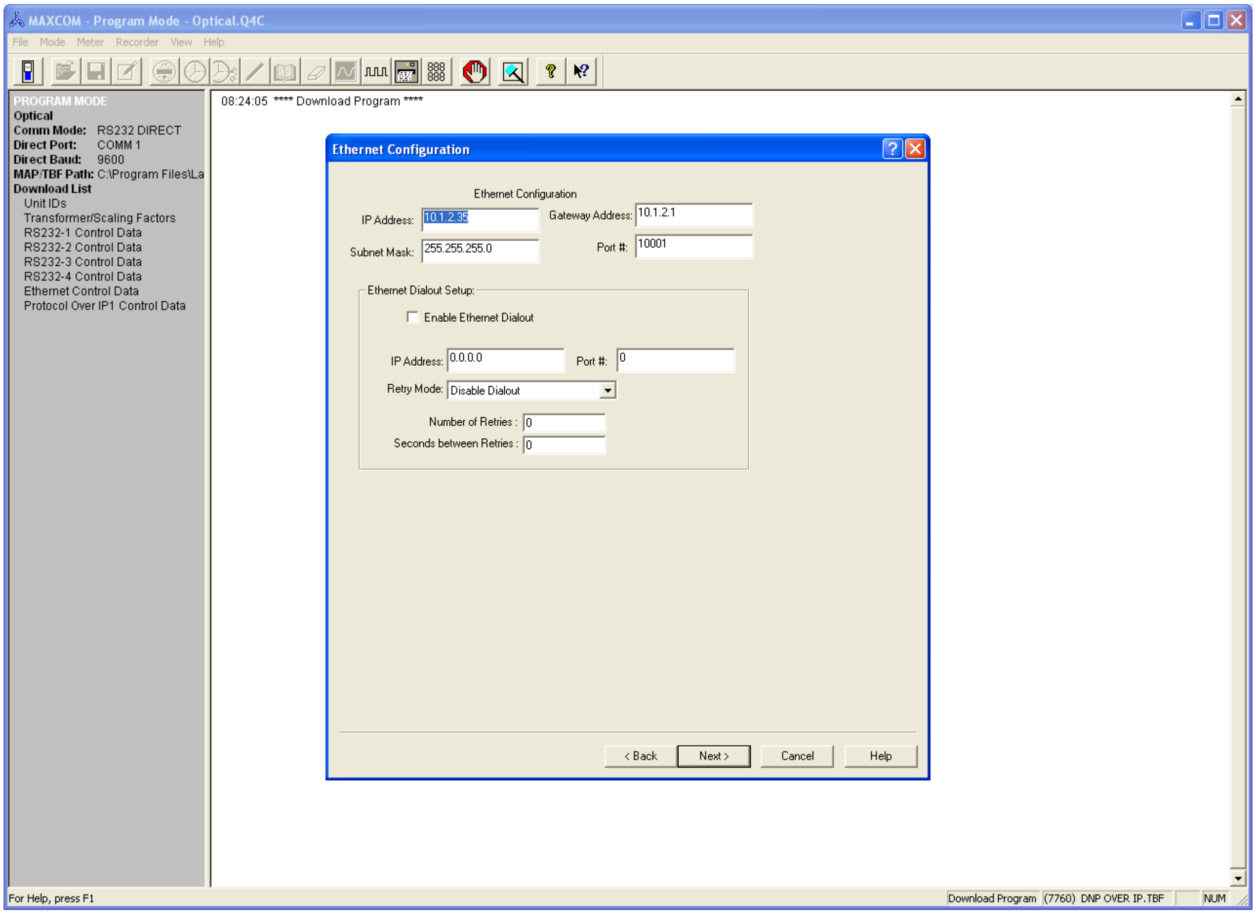


f. Select the “tbf” file for programming the meter

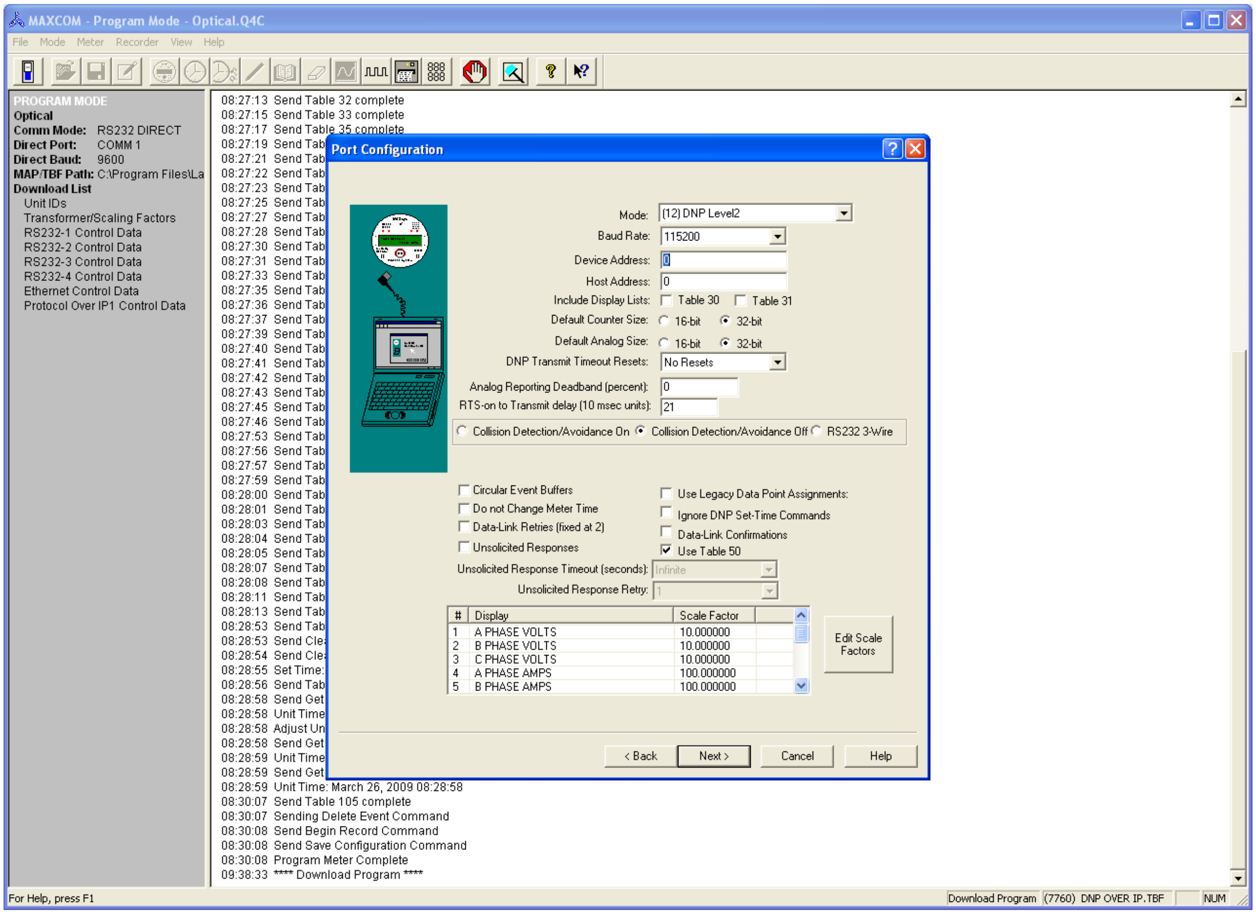
   a. You will get to review the RS232 Ports (None of the ports should be set at DNP).



a. You will get to review the RS232 Ports (None of the ports should be set at DNP).
b. You will get to review/change the Ethernet configuration.



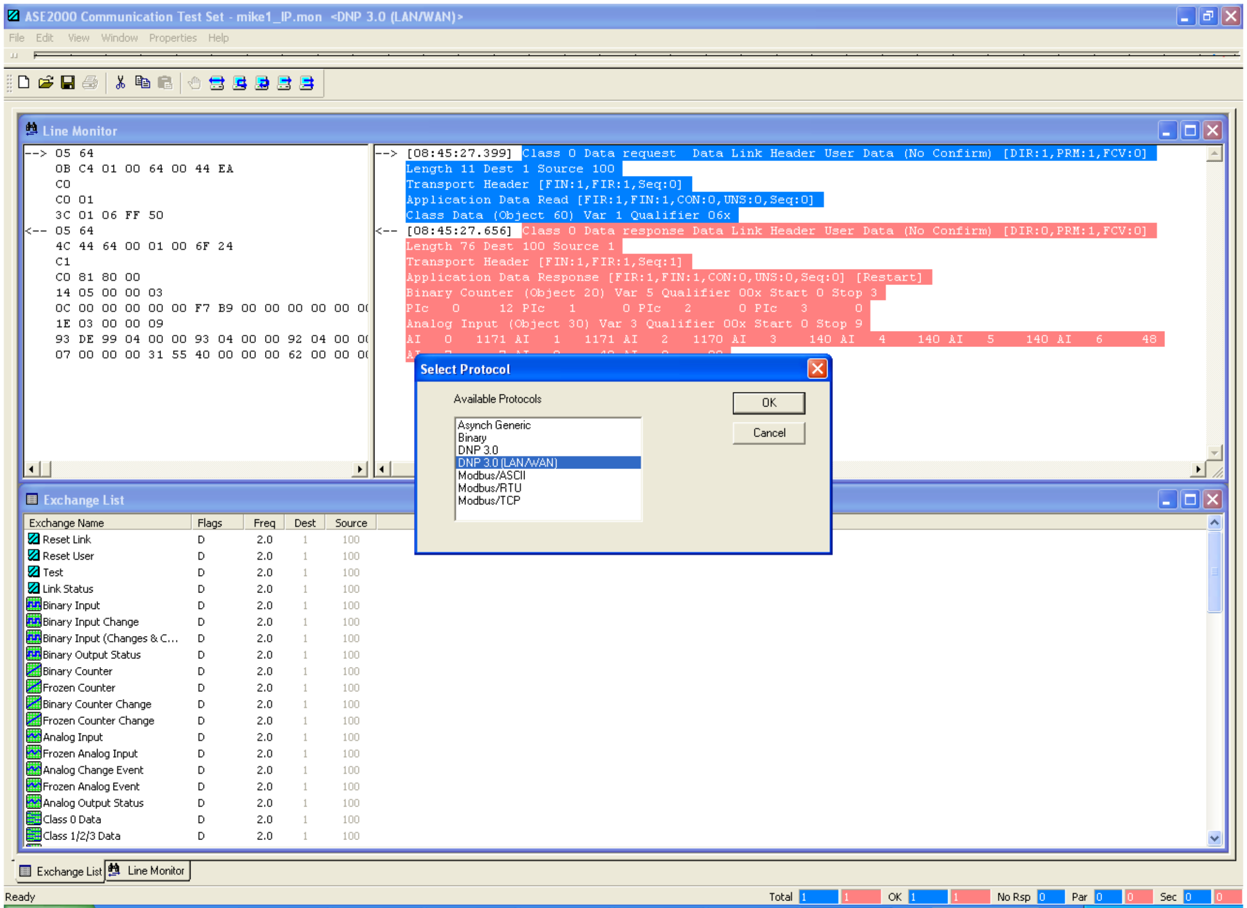
c. You will get to review/change the Ethernet configuration.
d. MAXcom will then complete the programming of the meter.



Step 3.

a. Run ASE2000 test set

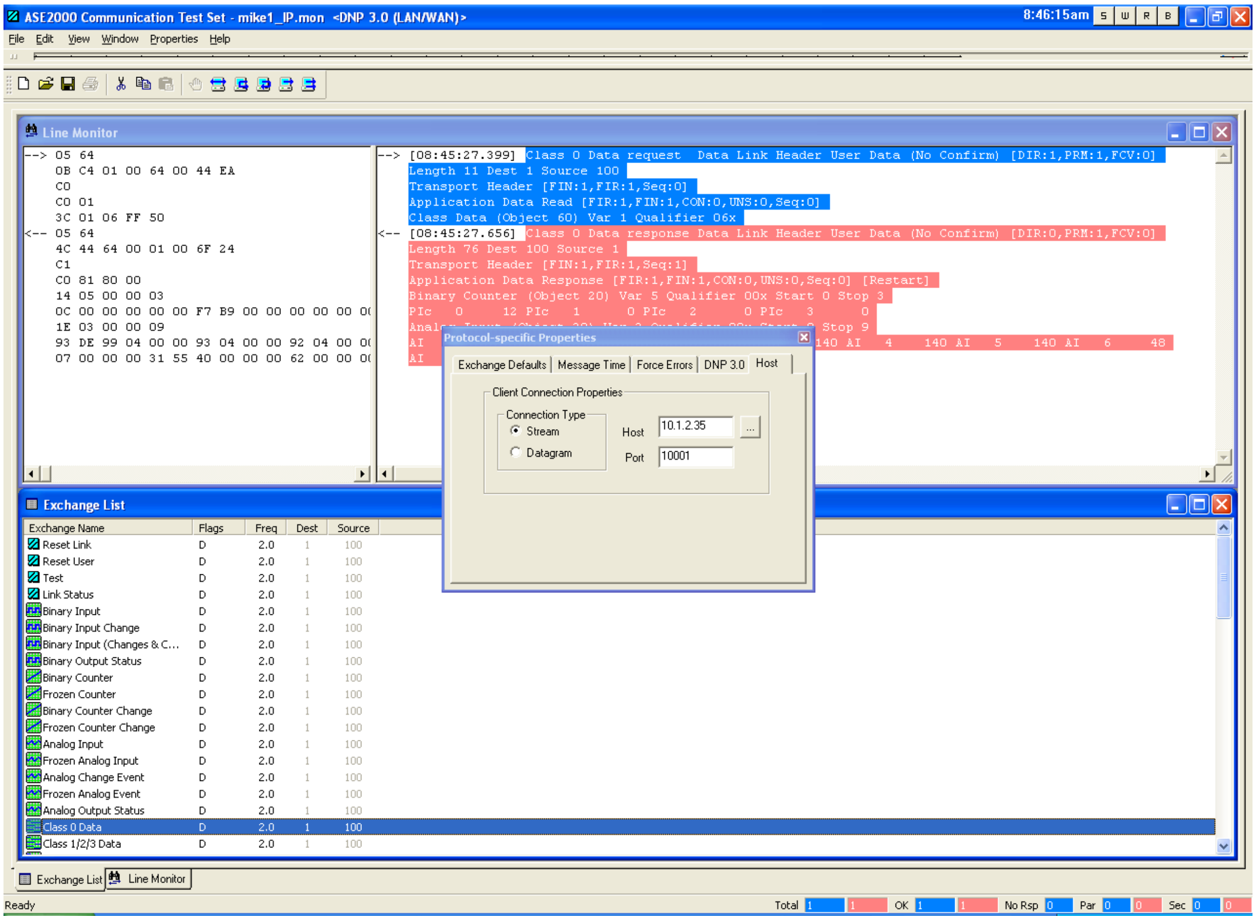
b. Select protocol (DNP 3.0 (LAN/WAN))



c. Edit "Properties" as needed.

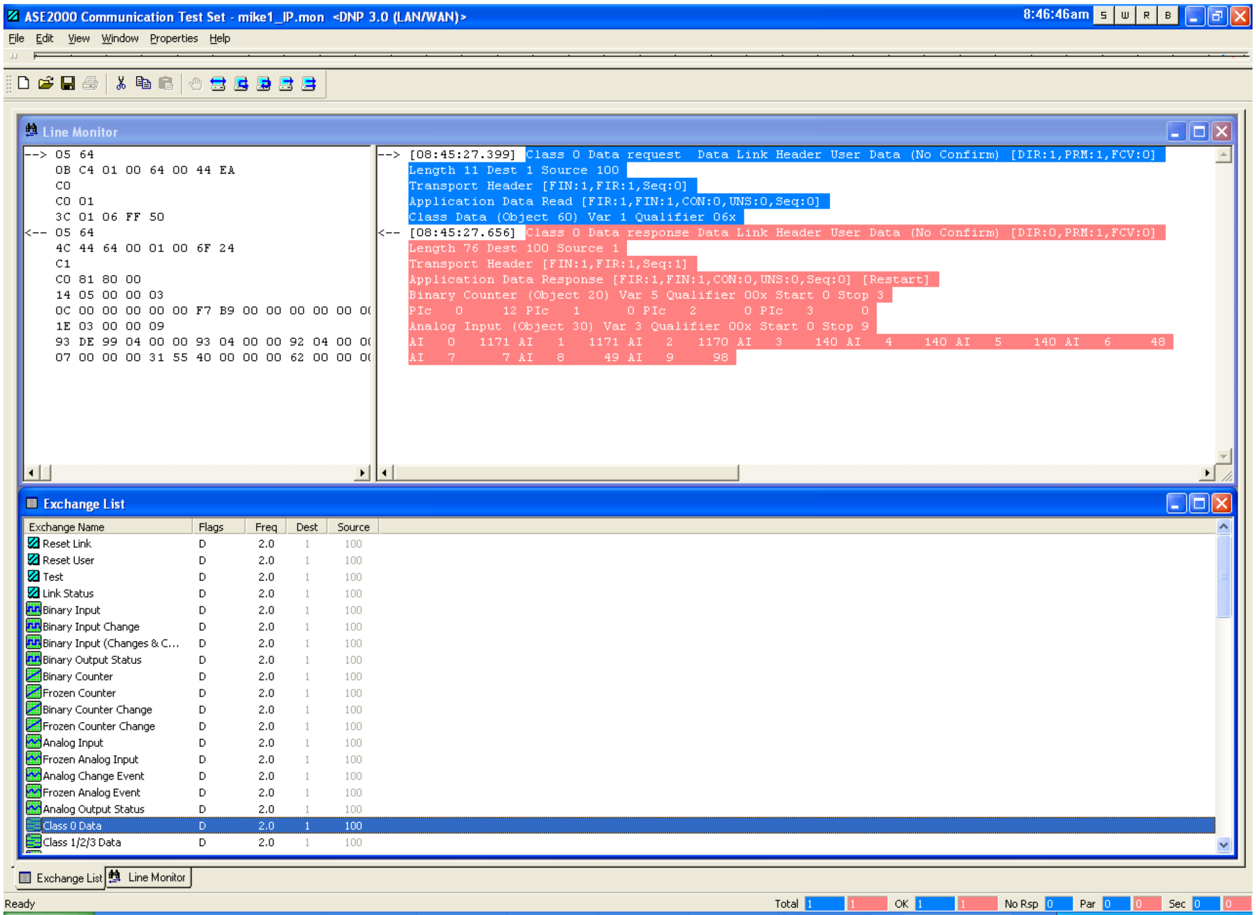
a. "Protocol-specific"

i. Host (Set meter IP and port)



d. Class 0 Read.

i. Data returned.



11.05.1 Programming The Elite Meter

ProgrammingThe MAXsys Elite Meter

Requirements:

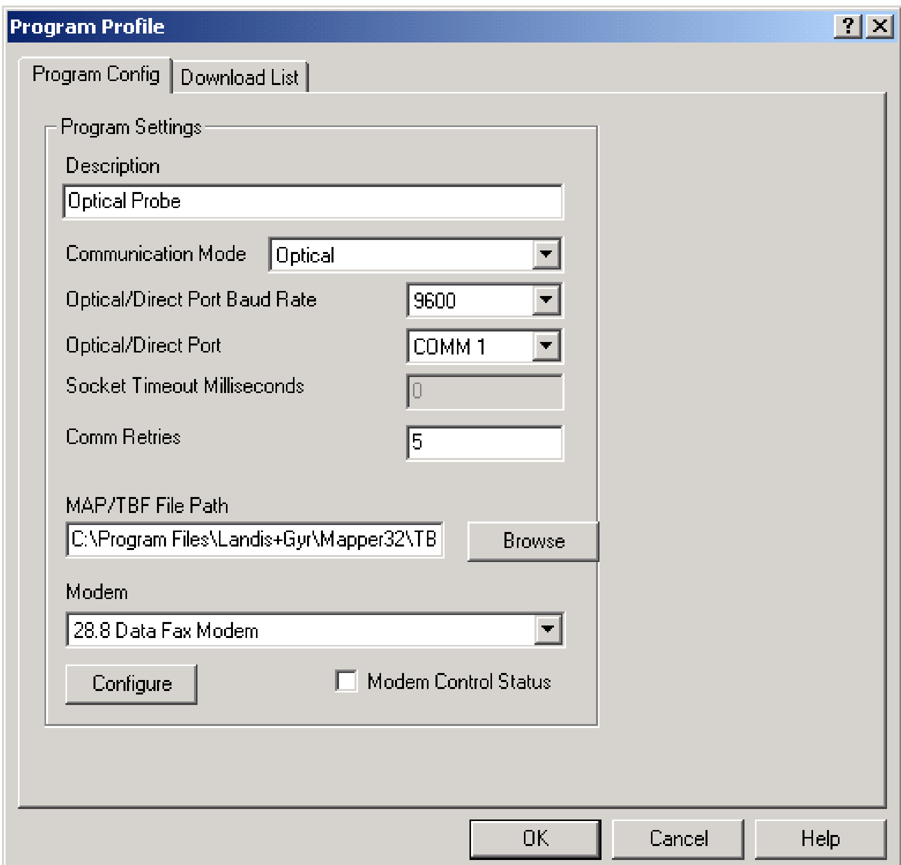
1. A meter file (tbf) for programming the meter.
   a. The "tbf" contains the controls tables which enable and set-up the functions that the meter is to perform.
2. Communications software (MAXcom) for loading the meter file (tbf) into the meter.
   a. MAXcom will download the meter program and allow the user to change any of the site specific values.
3. Optical probe (or RS232 cable) for connecting between the meter and the computer. Note: RS232-1 will require a null modem.
4. Computer
   a. The computer that will run the MAXcom software.

Prerequisite:

1. Load (install) the MAXcom software onto the computer that will be used to program the meter.
    a. Should be a Windows XP or 2000 system.
2. Have the meter powered up.

Process:

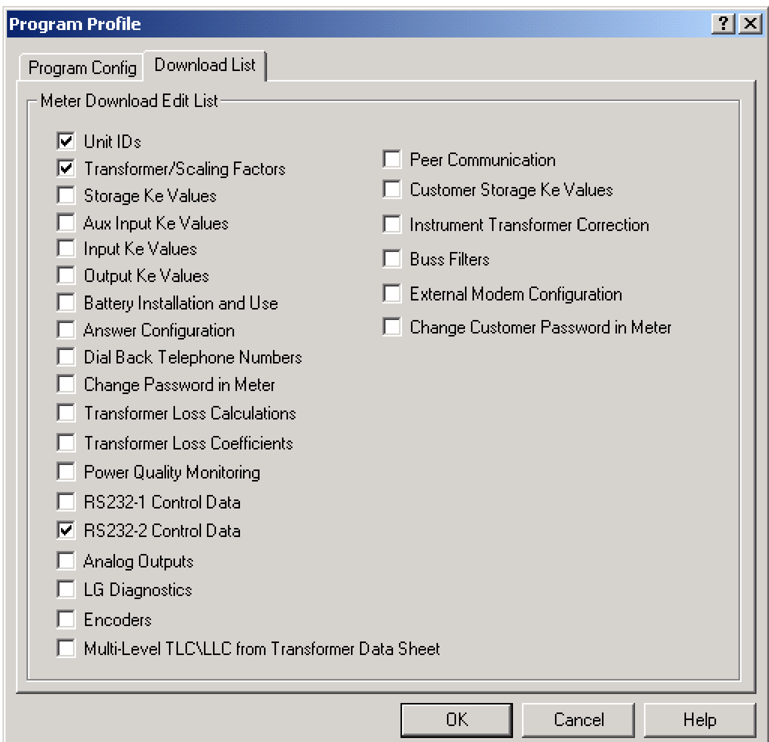
1. Run MAXcom
2. Be sure you are in the program mode not the data collection mode. You can switch by clicking on the first icon on the left side of the tool bar.
3. Set-up the communications parameters.
    a. Open the “program profile”, this is the 4th ion from the left (paper with a pencil).



    b. Set-up the program configuration tab first.
        i. Description: Information Only
        ii. Communication Mode: This how you will be communicating to the meter. Remember the meter must be programmed to communicate on the same port as MAXcom.

iii. Baud Rate: This is the speed you will be communicating to the meter. Optical is always 9600 baud.
iv. Port: This is the computer port that the optical cable will be connected for communicating to the meter.
v. Retries: This field should no be set to less than five (5).
vi. Path: This is the path to the location of the "tbf" files you will be using, when programming the meters.
vii. Modems: Use the windows set-up as a starting default.

c. Set-up the download tab next. This is where you will choose what you will set (change) when you program the meter, normally site specific.



d. This tab gives the customer a list of items that changed (edited) at the time the meter is being programmed. The customer will only be prompted for the checked items. The unchecked items will be loaded with the program (tbf) defaults. The example shows the most common items that are checked.

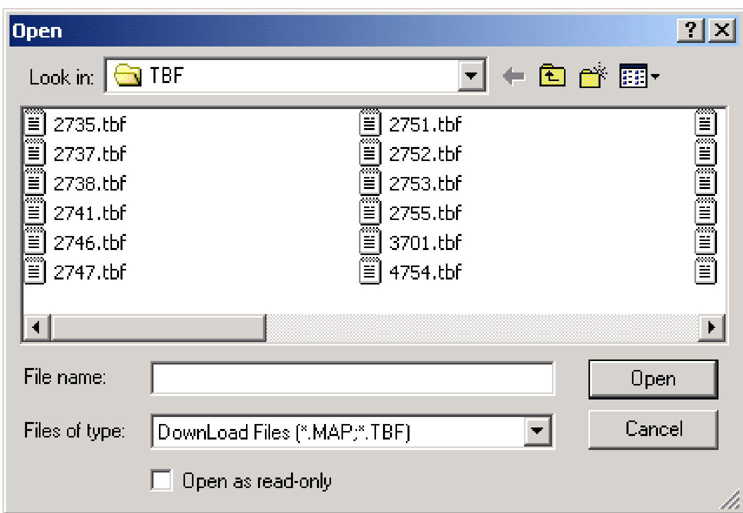
i. IDs: Each meter needs it own unique 7 digit number. The number can be any Hex value. The number is used when connecting to the meter and for data collection. If you do not have numbering plan and do not care what the number is, I would suggest you use the last 7 digits of the meter number.
ii. Transformer/Scale factors: This is where you will enter Transformer ratio (CTR x VTR) and scale factor as well as VT and CT factors. The "Transformer Ratio" and "Scale Factor" will only

affect the power values (Kwh, Kw, Kvarh, Kvar, Kvah Kva). The "Transformer Ratio" and "Scale Factor" affect all of the power values in the meter (Displays, Recorders and Output Relays). The "VT" and "CT" ratios only affect all voltage and current values in the meter except the vector information which is always secondary values.

iii. RS-232 control data: This will allow you to set to change the baud rate or port configuration within the protocol. If the port is configured for DNP or MODBUS the user can change address and other items depending on the protocol.

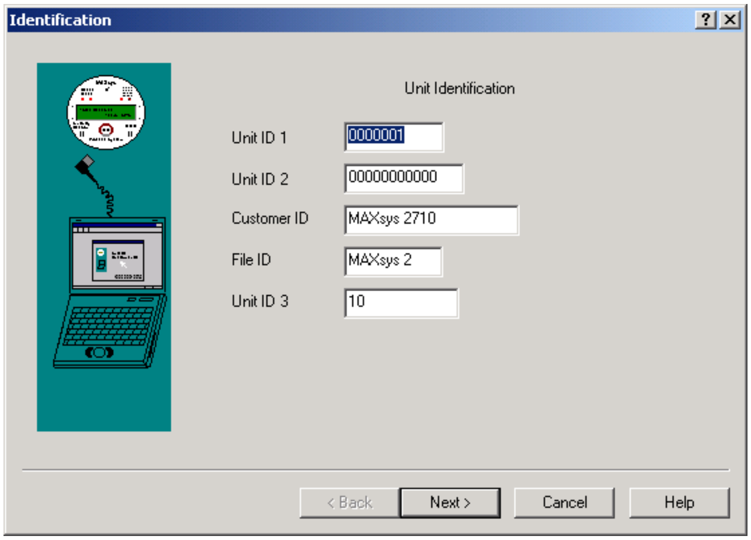
iv. After you complete checking the items, click "OK"

4. You can now program the meter.
   a. Connect the computer to the meter.
   b. Select, program meter this is the fifth icon from the left. You will then see the following screen.

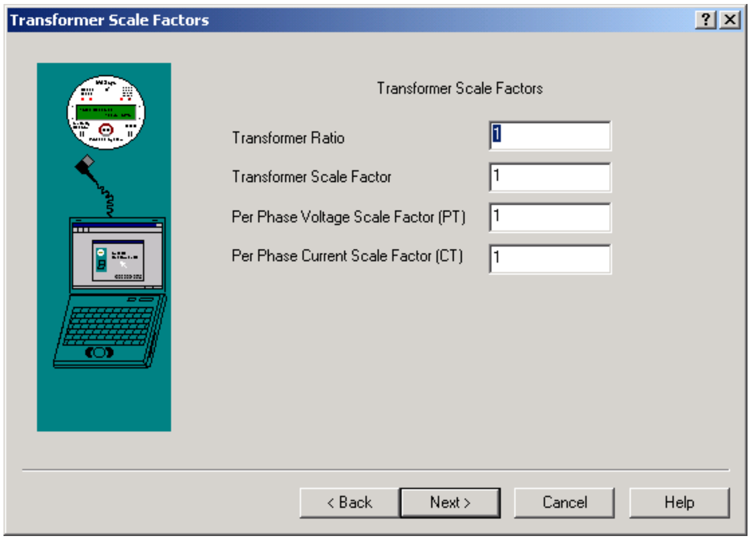


   c. Select the file you wish to use in programming the meter and click "open". You will then get the following screens.

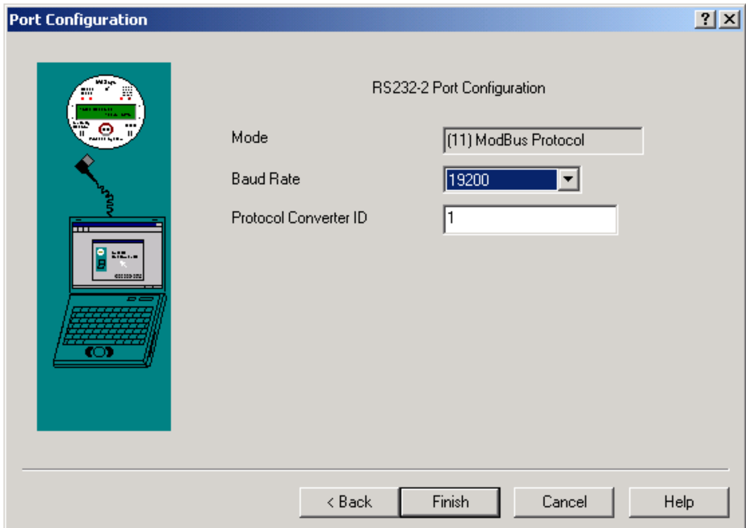
This screen is for setting the IDs. Only Unit ID 1 is required. The rest are for information only unless you are using the second data recorder and then ID 2 will become the ID for the second recorder.



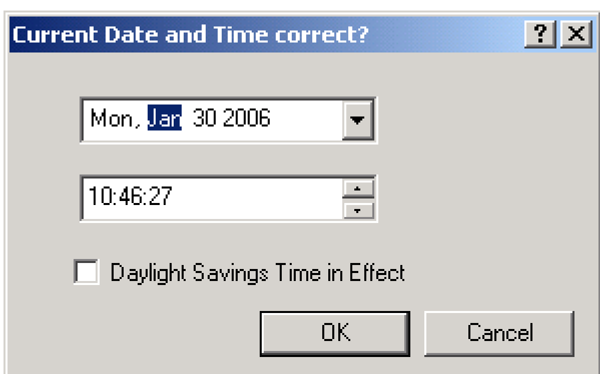
This is used to set the transformer factors. The first two (2) values effect power answers (Kwh/Kw, Kvarh/Kvar, Kvah/Kva. The last two only affect voltage and/or current.



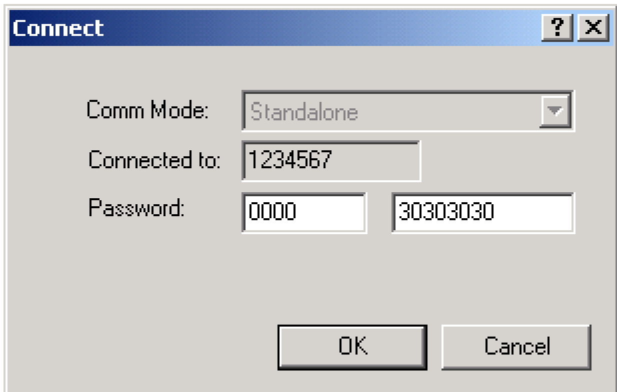
This is where the user can change the MODBUS address. Please note that MODBUS will only allow the baud rate and the ID to be edited at the time of programming. All other changes will need to be made in the program development software (Mapper32).



This is the last screen you will see before the MAXcom
Connects to the meter and starts programming. Click “OK”
If the time is correct and the computer’s time is running on daylight savings time, if so check the box and Maxcom will shift the time in the meter by one hour.



d. You will get the following screen. Click "OK" and the MAXcom will connect to the meter. If you are reprogramming a meter which has a password, you will need to enter the correct password.



e. You will get a warning, telling you that if you continue the will put the meter into idle mode and a new begin record time will be set. Click "OK" and the meter will be programmed.
f. The program will report back when the meter has been programmed.

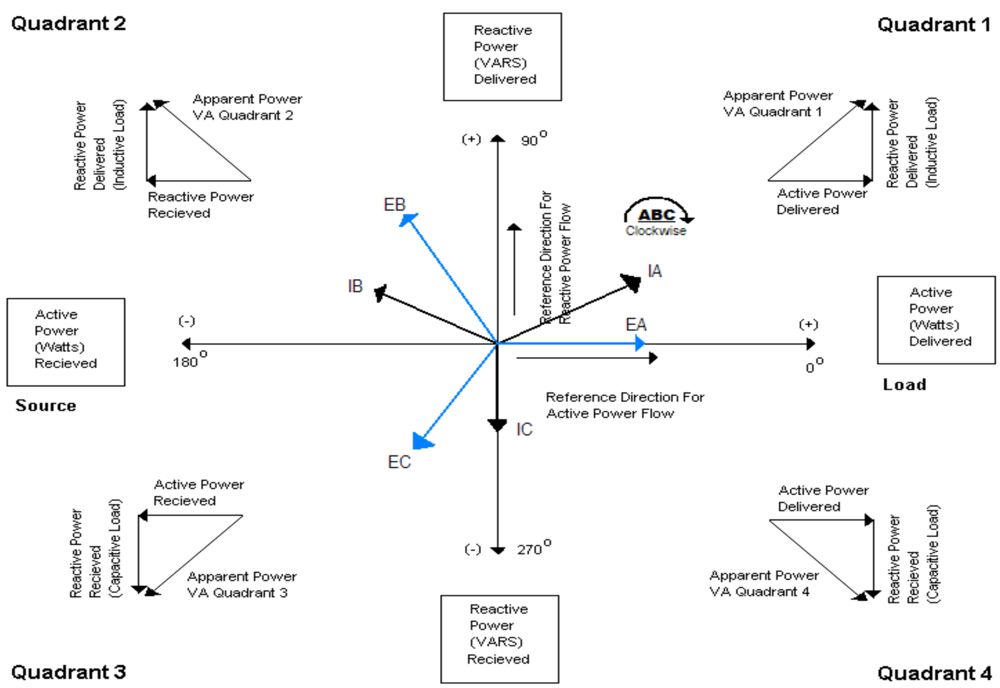
11.06.1 Power Flow and Naming Conventions

Introduction

In 1982 Raymond "Ray" Stevens published a paper "Power Flow Direction Definitions for Metering of Bi-directional Power". This paper helped reduce the confusion in the terminology associated with the naming of power quantities based on the direction of active and reactive power flow. The paper did not address leading and lagging current and Power factor. The illustration below came from the paper and has been adopted as a standard and is used in the Handbook for Electricity Metering.

Over the last 24 years we have all used and continue to use the same terms (words) when we are talking about bi-directional power flow. However over this period of time, we have made up some new terms and continue to have issues with some old terms "lead and lag". The big issue is that when two people are using the same terms they do not mean the same things. The intent of this paper is to help us not only say the same thing but to mean the same thing.

Illustration 1



Review

In using the above illustration to base the definition of power and the direction of the power flow, it is important that after the source and load have been defined for the metering point they can not be changed because active power flow changes direction.

Active Power (True Power): Watts

When the Active Power (Watts) flow from the "SOURCE" through the metering point and into the "LOAD" we say the Active Power (Watts) are being DELIVERED. Therefore when the Active Power is being supplied by the "SOURCE" into the load it will be referred to as Delivered Power (Watts) and has a positive sign.

When the Active Power (Watts) flow from the "LOAD" through the metering point and into the "SOURCE" we say the Active Power (Watts) are being RECEIVED. Therefore when the Active Power is being supplied by the "LOAD" into the source it will be referred to as Received Power (Watts) and has a negative sign.

Note: The Active Power is always on the x axis and does not fall into any of the four quadrants. Active power does not lead or lag it is delivered or received.

Reactive Power: Vars

When the Reactive Power (Vars) flow from the "SOURCE" through the metering point and into the "LOAD" we say the Reactive Power (Vars) are being DELIVERED. Therefore when the Reactive Power is being supplied by the "SOURCE" into the load it will be referred to as Delivered Reactive Power (Vars) and have a positive sign.

When the Reactive Power (Vars) flow from the "LOAD" through the metering point and into the "SOURCE" we say the Reactive Power (Vars) are being RECEIVED. Therefore when the Reactive Power is being supplied by the "LOAD" into the source it will be referred to as Received Reactive Power (Vars) and have a negative sign.

Note: The Reactive Power is always on the y axis and does not fall into any of the four quadrants. Reactive power does not lead or lag it is delivered or received.

Terms (Standard from the above illustration):
Delivered Kw/Kwh
Received Kw/Kwh
Delivered Kvar/Kvarh
Received Kvar/Kvarh

Apparent Power: Volt-amps

When the Active Power (Watts) flows from the "SOURCE" through the metering point and into the "LOAD" (Delivered Power) and the "LOAD" is resistive (No Vars) the Apparent Power (VA) will be on the x axis with Watts. Apparent Power has no sign or defined direction it is a vector quantity.

When the Active Power (Watts) flows from the "SOURCE" through the metering point and into the "LOAD" (Delivered Power) and the "LOAD" is inductive (Vars are present) the Apparent Power (VA) will be in Quadrant 1. Apparent Power has no sign or defined direction it is a vector quantity.

When the Active Power (Watts) flow from the "SOURCE" through the metering point and into the "LOAD" (Delivered Power) and the "LOAD" is capacitive (Vars are present) the Apparent Power (VA) will be in Quadrant 4. Apparent Power has no sign or defined direction it is a vector quantity.

When the Active Power (Watts) flows from the "LOAD" through the metering point and into the "SOURCE" (Received Power) and the "LOAD" is inductive (Vars are present) the Apparent Power (VA) will be in Quadrant 2. Apparent Power has no sign or defined direction it is a vector quantity.

When the Active Power (Watts) flows from the "LOAD" through the metering point and into the "SOURCE" (Received Power) and the "LOAD" is capacitive (Vars are present) the Apparent Power (VA) will be in Quadrant 3. Apparent Power has no sign or defined direction it is a vector quantity.

Terms (Standard from the above definition):
Kva/Kvah
Kva/Kvah Quadrant 1
Kva/Kvah Quadrant 2
Kva/Kvah Quadrant 3
Kva/Kvah Quadrant 4

Note: We also like to group our Kva/Kvah values based on the direction of power flow and then refer to them as Delivered and Received Kva/Kvah even though the Kva/Kvah has no sign or direction.

If we could (would) stop at this point there would be little to NO confusion. When we were talking about delivered and received power we would all be using the same words and mean the same thing. Therefore, when possible the above definition should always be used when referring to Active, Apparent and Reactive Power.

The paper did not address Leading and Lagging current or talk about Power Factor.

We will address the terms leading and lagging along with power factor later in this paper.

What's New

Additional Kvar/Kvarh Quantities

Some of the confusion comes when terms are used that fall outside of the standard power flow definitions. The following is a list on non-standard terms term that are used routinely.

Terms (non-standard or made-up names):
Kvar/Kvarh (absolute Del. + Rec.) with Delivered Power (Kw)
Kvar/Kvarh (absolute Del. + Rec.) with Received Power (Kw)
Kvar/Kvarh (Net, Del. - Rec.) with Delivered Power (Kw)
Kvar/Kvarh (Net, Rec. – Del.) with Received Power (Kw)

The first question maybe, what are the quantities and what are they used for? After talking to a number metering people, I found out they are quantities that are used to comply with billing (needs) tariffs and to get the same results as in the past using electro-mechanical meters. Names were then created (made up) that best describe the quantity or requirement.

The next question maybe, where (how) are the quantities being used? The two most common uses for the absolute values are for calculating Delivered and Received Kva/Kvah which is a made-up name for an undefined electrical quantity. The other application is in billing Kvar/Kvarh (absolute value) based on the flow of active power. The two most common uses for the net values are for calculating Kqh to be used with Delivered and Received Kw/Kwh. The other application is in billing Net Kvar/Kvarh (this is where the customer is given an equal credit for Received Kvar/Kvarh) based on the flow of active power.

The reason for the confusion is the terms (delivered and received) are being used interchangeable between non-standard and the standard names for Reactive Power. This allows one person to be talking about Delivered Vars as per Illustration 1 and the other person think he is talking about the non-standard terms (Kvar with Delivered Power).

The other term that causes confusion and the meaning is unknown when talking about Kvar/Kvarh is Leading and Lagging. The reason for the confusion is, Vars do NOT Lead or Lag, The quantities (term) for Vars is Delivered and Received. This is very important in bi-directorial applications. The only quantity that Leads or Lags is current and it Leads and Lags in reference to voltage.

We will look at leading and lagging current later in this paper.

Additional Kva/Kvah Quantities

Some of the confusion comes from terms that we use that fall outside of the standard power flow definitions and naming convention as described above. The following is a list on non-standard terms that are used routinely.

Terms (That are non-standard or have made-up names):
Kva/Kvah with Delivered Power (Kw)
Kva/Kvah with Received Power (Kw)
Kva/Kvah Quadrant 1 Only
Kva/Kvah Quadrant 3 Only

Please note the non-standard terms are not defined electrical quantities. They are one electrical value (Kva/Kvah) that is being referenced to, in conjunction with a standard defined electrical quantity (Kw/Kwh). The Quadrant 1 and 3 go back to the old electro-mechanical metering days when the reactive metering package was made-up of one Kwh and one Kvarh meter and a phase shifting transformer. The Kva/Kvah was then calculated base on the results of the Kwh and Kvarh meter.

Additional Terms (Lead and Lag)
The terms lead and lag should only be used in reference to current. The current will be in phase with the voltage or it can lead or lag the voltage depending on the device taking active power. The terms leading or lagging current is always viewed from the perspective of the point which is supplying the active power. We are going to look at the terms leading and lagging current in conjunction with the same illustration (see illustration 1) that was used to define power terms as before. To help understand the labels for leading and lagging current and help reduce the confusion I have changed the reference from Load to IPP and Source to System (see illustration 2). The meter has been connected to register delivered active power when the IPP is taking power from the system and the meter will register received power when the system is taking active power from the IPP.

Reference 1
In the first set of examples (conditions) the IPP is seen as the load by the system which is providing the active power. When the IPP is taking active power from the system (which is 95% of our metering installations) we say the power is being delivered. The three conditions which follow should help us to understand leading and lagging current when the active power is in the
delivered direction.

Condition 1;
When the IPP appears as a resistive device to the system, this will cause the current to be in phase (not leading or lagging) with the voltage and the Kva will be on the x axis with the active power (Kw delivered) from the system.

Condition 2;
When the IPP appears as an inductive device to the system, this will cause the current to lag the voltage and the Kva will move into quadrant 1. The IPP is now taking both active power (Kw delivered) and reactive power (Kvar delivered) from the system.

Condition 3;
When the IPP appears as a capacitive device to the system, this will cause the current to lead the voltage and the Kva will move into quadrant 4. The IPP is now taking active power (Kw delivered) from the system and sending reactive power (Kvar received) back to the system.

Reference 2
In the second set of examples (conditions) the System is seen as the load by the IPP which is providing the active power. When the IPP is sending active power to the system

(which is 5% of our metering installations) we say the power is being received. The three conditions which follow should help us to understand leading and lagging current when the active power is in the received direction.

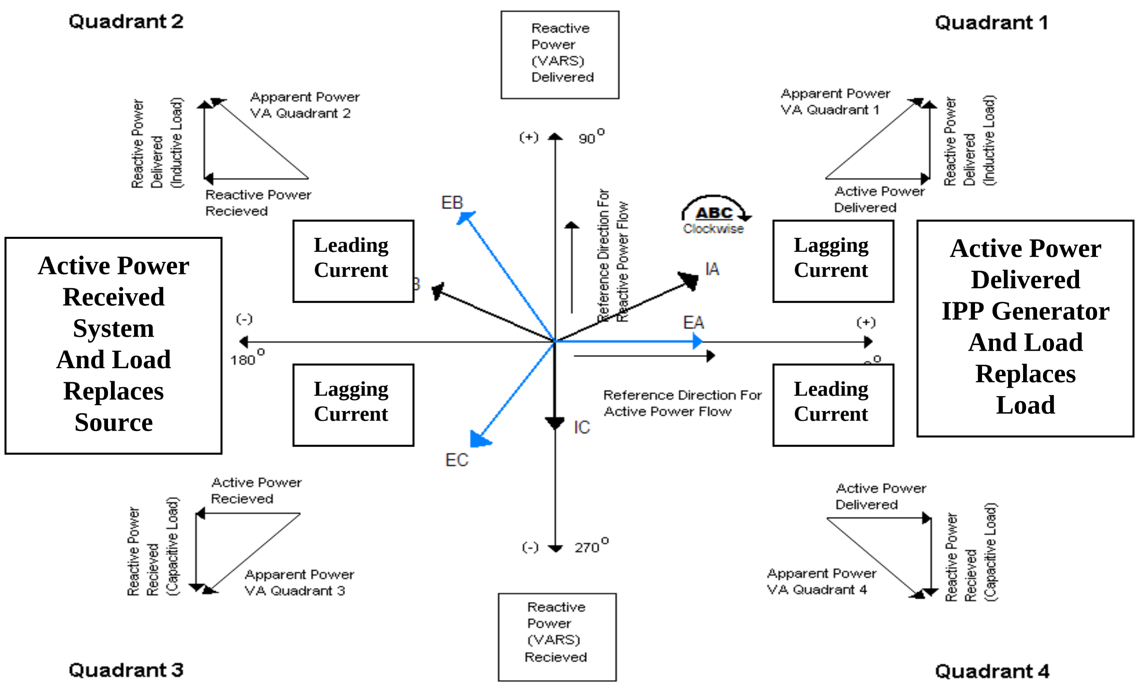
Condition 1A;
When the System appears as a resistive device to the IPP, this will cause the current to be in phase (not leading or lagging) with the voltage and the Kva will be on the x axis with the active power (Kw received) from the IPP.

Condition 2A;
When the System appears as an inductive device to the IPP, this will cause the current to lag the voltage and the Kva will move into quadrant 3. The System is now taking both active power (Kw received) and reactive power (Kvar received) from the IPP.

Condition 3A;

When the System appears as a capacitive device to the IPP, this will cause the current to lead the voltage and the Kva will move into quadrant 2. The System is now taking active power (Kw received) from the IPP and sending reactive power (Kvar delivered) back to the IPP.

Illustration 2



Additional Values (Power Factor)
Power Factor, is another value that I hear people sticking on the terms lead and lag. Power Factor is the ratio between true and apparent power. The ratio will always be between 0.0 and 1.0 and will not have a sign. The following terms are commonly used (naming conventions) for Power Factor.

Power Factor
Delivered Power Factor
Received Power Factor
Average Power Factor
Average Delivered Power Factor
Average Received Power Factor

Power Factor: is the ratio between true and apparent power (normally the instantaneous value).

Delivered Power Factors: is the power factor associated with delivered power (normally associated with a maximum demand value).

Received Power Factors: is the power factor associated with received power (normally associated with a maximum demand value).

Average Power Factor: What is average power factor? The best answer that I found, was average power is the ratio between the accumulated kwh and Kvah over some period of time, normally between demand resets.

Avg. Del. Power Factors: is power factor associated with delivered power.
Avg. Rec. Power Factors: is power factor associated with received power.

Summary
Power Values (Kw/kwh, Kvar/Kvarh and Kva/Kvah): The best naming convention would be to stay with Delivered and Received (Illustration 1).

Leading and Lagging: Use these terms for describing the relationship of current to voltage. Leading and Lagging is normally viewed from the perspective of the supplier of active energy (Illustration 2).

Power Factor: Is the ratio between true and apparent power. Power factor does not lead or lag and has no sign. Power factor is normally viewed from the perspective of the supplier of active energy.

11.07.1 Form 35 Meters

Understanding Form 5and 35 Meters

The forms 5 and 35 meters are known as “3-wir Delta” meters and 2 element meters. The meter is normally used for metering 3-wire Delta services. In the electro-mechanical meter there are two potential coils and 2 current coils. The results in a three phase circuit at unity power fact is W= (Wa = (Va x Ia x .866) + (Wc= (Vc x Ic x .866)). The reason for the (0.866) in the calculation is the current and the voltages are displaced by 30 degrees. The 30 degrees displacement is only present in a three phase circuit at unity power factor and watts will equal Volts x Amps x 1.732 x PF. However when testing or running the meter single phase (series), the 30 degree displacement is not present causing all of the voltages and currents to be in phase, therefore watts will equal Volts x Amps x 2 x PF. When you applied 120 volts and 5 amps with the meter connected 3-phase the meter would read 1039 watts or 1.039 Kw, however if the same meter was connect series (single-phase) the meter would register 1200 watts or 1.2 Kw. This is why with the same load applies you will get a deferent percentage depending on the how you run the test (single or three phase). This will cause your full load test point (watts) to be different in single and 3-phase testing with the same load applied.

Understanding the Form 35 Elite Meters

The form 35 meters are known as “3-wir Delta” meters and 2 element meters. The meter is normally used for metering 3-wire Delta services. In the electro-mechanical meter there are two potential coils and 2 current coils. The results in a three phase circuit at unity power fact is W= (Wa = (Va x Ia x .866) + (Wc= (Vc x Ic x .866)). The reason for the (0.866) in the calculation is the current and the voltages are displaced by 30 degrees. The 30 degrees displacement is only present in a three phase circuit at unity power factor and watts will equal Volts x Amps x 1.732 x PF. However when testing or running the meter single phase (series), the 30 degree displacement is not present causing all of the voltages and currents to be in phase, therefore watts will equal Volts x Amps x 2 x PF. When you applied 120 volts and 5 amps with the meter connected 3-phase the meter would read 1039 watts or 1.039 Kw, however if the same meter was connect series (single-phase) the meter would register 1200 watts or 1.2 Kw. This is why with the same load applies you will get a deferent percentage depending on the how you run the test (single or three phase). This will cause your full load test point (watts) to be different in single and 3-phase testing with the same load applied.

Understanding TLC in Form 5 and 35 Meters

Power transformer losses are calculated based on the phase voltages and phase currents in the meters. The losses are then compared to the measured power to arrive at the percent losses. Therefore the voltage, current and power measurements will all play a part in controlling the percent losses. When the measured voltages and the currents in the meter are the same for both single or 3-phase testing, the losses will be the same in both tests (lets say the looses are 10). The next question is, does the power measurement in both single and 3-phase testing with the same load applied, provide the same results. Based on the information above we know in a form 5 or 35 meter the results for power (watts) will be different between single and 3-phase testing. Using the power numbers (Watts) from the above, when the meter is tested 3-phase the percent losses will be 10/1039 or 0.96 %. If the meter is tested series (single phase) the percent losses will be 10/1200 or 0.83 %. This is the reasons for a 3-phase and single phase TLC test sheet.

Understanding TLC in Form 35 Elite Meters

Power transformer losses are calculated based on the phase voltages and phase currents in the meters. The losses are then compared to the measured power to arrive at the percent losses. Therefore the voltage, current and power measurements will all play a part in controlling the percent losses. Because the voltages and current values are the same in the Elite meter when testing single and 3-phase, the losses will be the same in both tests. The next question is does the power measurement in both single and 3-phase testing with the same load applied provide the same results. Based on the information above we know in a form 35 meter the results for power (watts) will be different between single and 3-phase testing. Using the numbers from the above when the meter is tested 3-phase the percent losses will be 10/1039 or 0. 96 %. When the Elite meter is series tested because of the difference in the power value the percent losses will be 10/1200 or 0. 83 %. This is the reasons for a 3-phase and single phase TLC test sheet.

Entering TLC Data into the Elite Meter

Transformer loss information is entered into the meter using MAXcom. MAXcom will take the information and calculate the copper and iron values that the needs and loads them into the Elite meter. The information can be provided to MAXcom using "Transformer Loss Calculations" (information from the transformer data sheet) which is recommended or using "Transformer Loss Coefficients" (percent losses) will require the user to tell how the percentages were calculated. Is the percentage on 3-phase or single phase calculations.

11.08.1 Maximum Output Pulse Rate

Maximum Output Rate for Pulse Outputs

The maximum rate for a given pulse output in a meter is not a simple figure to determine because the output circuitry has been designed to minimize current surges and short term power requirements and yet be capable of satisfying electric utility requirements.

This design results in interaction between the functions of the outputs such that the maximum average switching rate of a particular output depends on the switching requirements placed on the other outputs in the system. This, in turn, depends on the settings of the minimum delays on the outputs and the switching rate required of the outputs. For example, if outputs 2, 3, and 4 are assigned to a function that requires them to switch twice per minute (such as the end of interval function in a system which uses 1-minute intervals), and if the minimum delay time of output 1 is set to 10 milliseconds, its maximum average switching rate is almost 100 transitions per second, specifically:

(1/.01 - 3 (2/60)) * .9 = 89.9 transitions per second with the values:

1/.01 is the reciprocal of the minimum delay time of output 1

3 (2/60) is the sum of the expected maximum switching rates

The factor .9 is a safety factor which allows for asynchronous operation within a multitasking environment.

The "minimum dwell time" assigned to a particular output is the minimum time that the output will "dwell" in a particular state. For various reasons, the output may not switch at the end of each minimum dwell time even though output transitions may be queued up to be output. These reasons include the fact that the switching function is a round-robin operation and other outputs may be ready to be switched, or that the switching task is delayed in operation because of higher priority processing.

Generally, the minimum dwell time should be set to the **smallest value** consistent with the requirements of the external device to be driven if it is necessary to maximize the average switching rate.

Rule of Thumb: Max output rate for relay outputs in a meter with 12 relay outputs all in use is 8 pulses (transitions) per second. 100 ms (not below this value) is the recommended minimum pulse width (aka minimum dwell time).

A general formula for the maximum average switching rate of a particular output in a system with MAX_OUTPUTS = N can be stated as follows:

MASRn = (1/MDTn - TSRo) * .9

where MASRn is the maximum average switching rate in transitions per second for output n.

MDTn is the minimum dwell time in seconds assigned to output n.

TSRo is the sum of the expected maximum switching rates (MSR's) in transitions per second of all other outputs in the meter.

TSRo is a value which must be arrived at based on how the other outputs are to be used. For certain uses, the value is known and precise. For example, if an output is used for end-of-interval and the interval is 15 minutes, the MSR for this output is 2/(60 * 15), because the output is switched twice, on and off, each 60 * 15 seconds for an average switching rate of .002 transitions per second. This obviously has a negligible effect on the operation of the other outputs.

If the rate of an output is variable depending on input transition rates (for example, an output that is mapped to a meter pulse initiator or to a totalizer), an estimate must be made of the maximum average transition rate that may be expected on that input. Solving the above equation for the general case, in which all outputs may be required to put out high pulse rates, becomes very complex requiring the solution of simultaneous equations to obtain the absolute optimum maximum transition rate for each output. Fortunately, there is a simplified approach to the problem that will always yield a workable solution that is ordinarily satisfactory.

The following example, which is just about a worst case, will illustrate a method of determining what the output Ke's and the minimum dwell times should be for four outputs feeding four external recorders of different makes from four different sources within the buss structure of the meter. The maximum power values used in the example are design parameters for the source meters. The recorders and their parameters are fictional but representative. The totalizer is totalizing inputs 1, 2, and 3.

OUTPT	SOURCE	SOURCE MAX PWR	DEST RCDR	RCDR MAX RATE	RCDR MIN DWELL
1	INPUT 1	2.0 KW	A	10 TPS	50 MS
2	INPUT 2	6.0 KW	B	10 TPS	50 MS
3	INPUT 3	6.0 KW	C	10 TPS	50 MS
4	TOT 1	14.0 KW	D	15 TPS	40 MS

We must set the output minimum dwell times the same as the recorder minimum dwell times so that the recorder does not miss data. We know also that in the output round-robin switching sequence, it is possible that each output may have to wait an additional 30 milliseconds after its minimum dwell time expires before it can be switched since switching can occur only approximately every 10 milliseconds and there are 3 other relays to be considered. Therefore, in determining the maximum transition rate, we have to add 30ms to the minimum

dwell time and calculate a rate. Then we can add a safety factor to account for overhead delays which may occur in a multitasking system. To do this, we can multiply by the factor 0.9. This gives a conservative design which is usually satisfactory for most purposes. Note that this system will only work if ALL outputs meet these requirements.

In the example, the rates for outputs 1 through 4 are calculated as follows:

$$MTR1 = (1/(.050 + .030)) * .9 = 11.25$$
$$MTR2 = (1/(.050 + .030)) * .9 = 11.25$$
$$MTR3 = (1/(.050 + .030)) * .9 = 11.25$$
$$MTR4 = (1/(.040 + .030)) * .9 = 12.86$$

OUTPT	OUTPUT MIN DWELL	OUTPUT MAX RATE	OUTPUT Ke
1	50 MS	11 TPS	.00005
2	50 MS	11 TPS	.00015
3	50 MS	11 TPS	.00015
4	40 MS	13 TPS	.00030

Note on Queuing of Negative Value Pulses:
Starting in 11/94, certain firmware versions of the meter support queuing of 1-second negative value pulses for output relays programmed to output a pulse stream. As the value of pulses goes positive, the accumulated pulse output register will track toward positive. No pulses will be output until the accumulated pulse output register crosses zero and becomes positive again. The function is enabled by answering YES to the prompt Queue Up Negative Values in the Table Builder software when building table files for formatting.

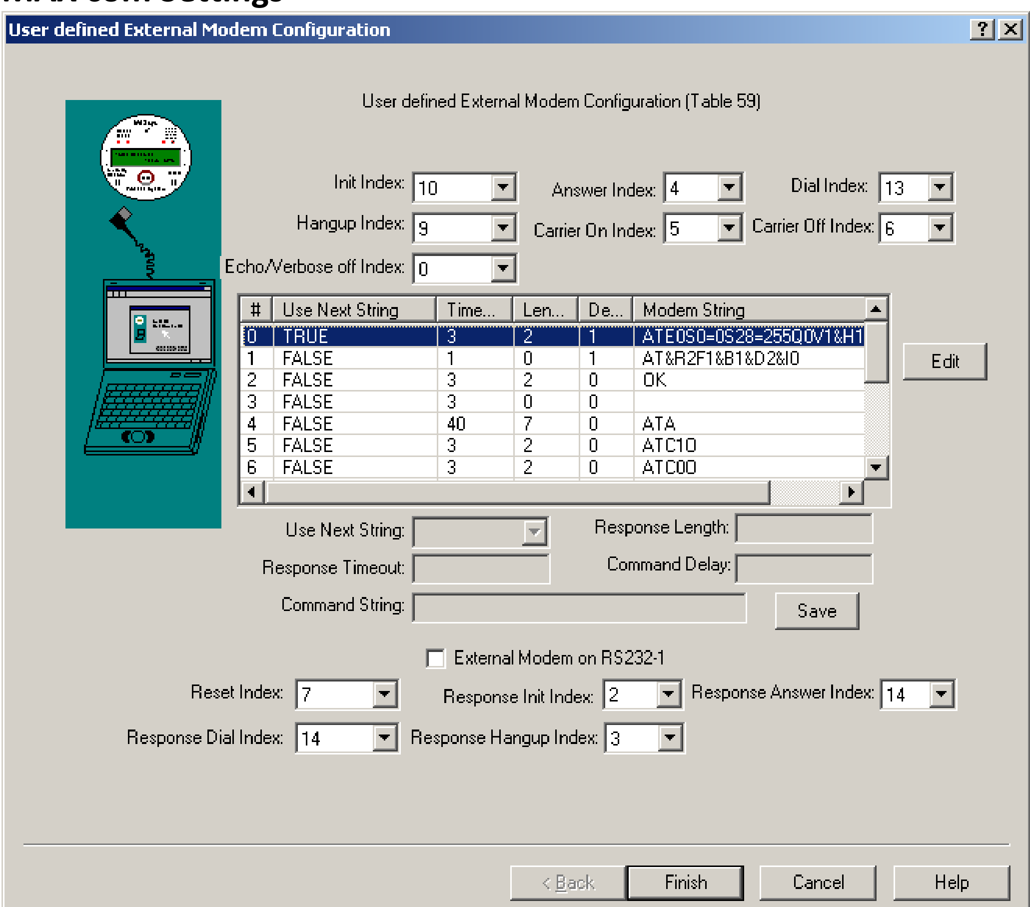
11.09.1 External Modem configuration

External Modem Set-up for RS232-1
For U.S. Robotics (5686)

Modem DIP Switch Settings

1. UP, Data Terminal Ready Normal
2. UP, Verbal Result Codes
3. DOWN, Display Result Codes
4. UP, Echo Offline Commands
5. UP, Auto Answer ON First Ring or Higher If Specified In NVRAM
6. UP, Carrier Detect Normal
7. DOWN, Load Factory Defaults
8. DOWN, Smart Mode

MAX com Settings



Init Index = 10
Answer Index = 4
Dial Index = 13
Hang up Index = 9

Carrier On Index = 5
Carrier Off Index = 6
Echo/Verbose off Index = 0
External Modem on RS232: Selected
Reset Index = 7
Response Init Index = 2
Response Answer Index = 14
Response Dial Index = 14
Response Hang up Index = 3

Check Index 10
Use Next String = 1
Response Time Out Seconds = 3
Response Length = 0
Command Delay = 0
Command String = AT&F0&N0&U0&B1

Check Index 11
Use Next String = 0
Response Time Out Seconds = 3
Response Length = 0
Command Delay = 0
Command String = AT&D0V1X1S7=55S10=50S27=32

Check Index 13
Use Next String = 0
Response Time Out Seconds = 40
Response Length = 8
Command Delay = 0
Command String = AT&K0&N0&U0D

Other Requirements

1. Set or edit RS232-1 port on the meter to mode (6) RS232 Direct
2. Baud Rate: 9600 0r 19200
3. For dial Out you will need to set the dial conditions using MAXcom
4. In the EVM software: Set the EVM INIT modem string-1 to: ATE0&F0&N0&U0&B1&D0V1X1S7=55S10=50S27=32

11.10.1 Peer-To_Peer Configuration

Peer-To-Peer Overview

Peer-To-Peer communications allows multiple meters to transfer real time information (numeric and status) between each other without the granularity and time delay of pulses. This allows for real time (1 second) displays, logic control and analog outputs without using averages (15 second average with updating each second) to allow for the delays and the granularity of the pulses.

Pulse Granular Information

This example shows the value (weight) of one pulse and the error it causes in the calculations. The error is based on +/- one pulse over the interval. It can be seen that the error increases as the interval (time) decreases. This becomes very important when calculating one second data. The magnitude of the error continues to grow when summing and netting multiple meters because of delays and granularity issues within each of the meters supplying pulses.

Note in this example the following values were used for the calculation.

Pulse = 0.0002 KWh, Multiplier = 10,000

Time	Energy	Demand/Pulse
1hr.	0.0002 KWh	2 KW
30min.	0.0002 KWh	4 KW
15min.	0.0002 KWh	8 KW
5min.	0.0002 KWh	24 KW
1min.	0.0002 KWh	120KW
1sec.	0.0002 KWh	7200 KW

The Peer-To-Peer communications does not require the addition of an option board. Therefore this function will not use up a card slot that could be used for other options. This feature is under soft-key control. The installation cost is reduced because the number of conductors running between the meters will be reduced to one (1) wire, and shielded cable should not be required. When upgrading old installations which were using pulses, the wires which were used for the pulse outputs can be reused for the Peer-to-Peer communications 20ma current loop.

Communications Set-up

This following provides information on the wiring of the Peer 2 Peer current loop. The peer 2 peer loop should not be turned on until all of the meters on the loop have been programmed.

Specifications

The communication for peer 2 peer is normally done over the 20ma communication current loop. The current loop must be powered with an external 20ma current source. We recommend using an “Acopian” Power Supply, part number P050MX35. We also recommend a ballast resister of 200 ohms be used in series with the power supply. Note: You can also use the Black Box current loop driver, however you will be limited to two (2) maybe three (3) meters.

Power Supply Set-up

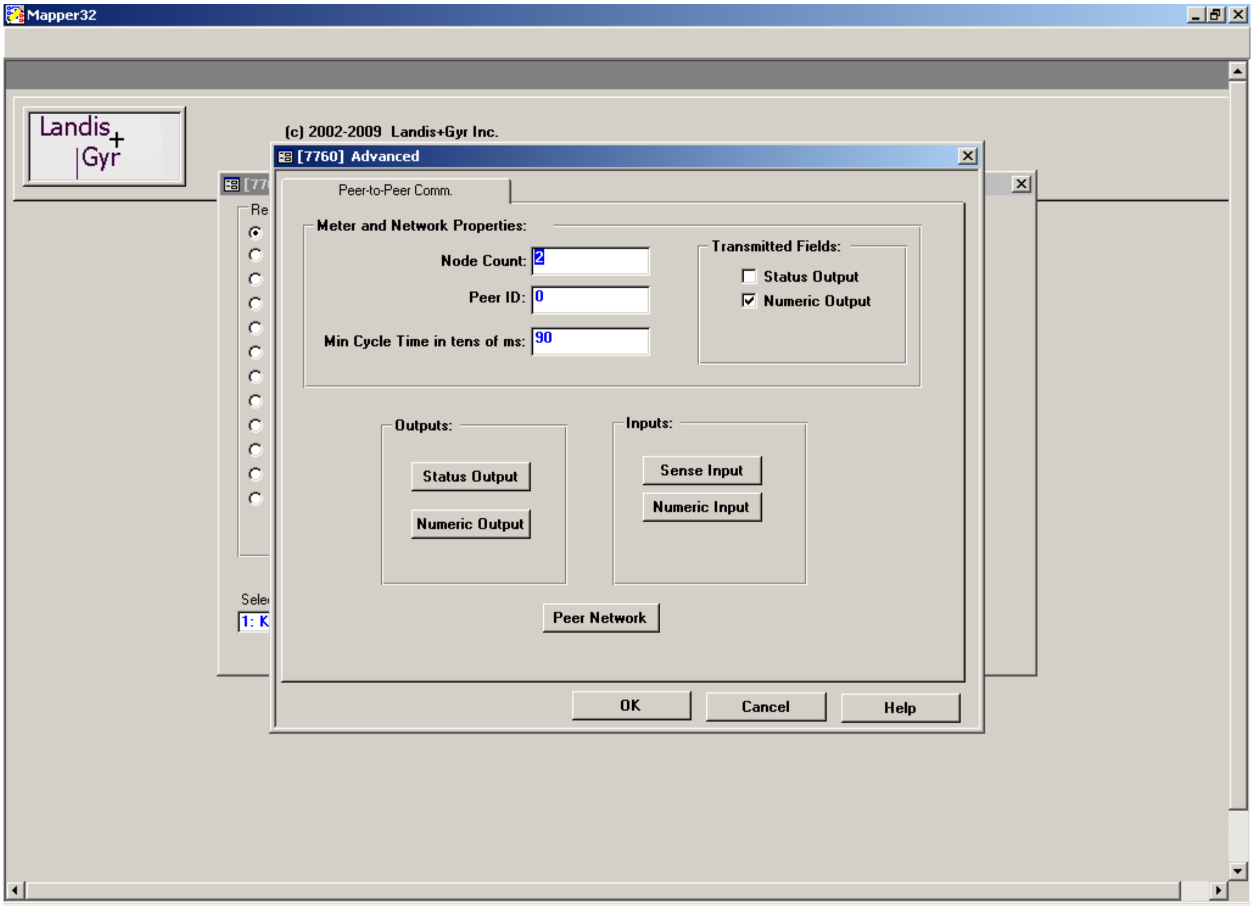
Follow the instructions that come with the power supply. Follow the instructions for setting up the constant current operation and set the limit at 20ma. After setting the current for 20ma you will then need to limit the voltage based of the following table.
Table

Number of meters	Set Voltage
2	15
3	21
4	26
5	31
6	37
7	40
8	42
9	45
10	50

Please note we do not recommend more than 7 meters when using the current loop and we recommend you always try and keep the voltage at or below 37 volts. When the voltage is set above 42 volts, the risk of the current loop failing increases as you increase the voltage. When more than 7 meters need to be on the peer 2 peer network, other communications ports should be considered. The current loop is the best option for good communication when possible.

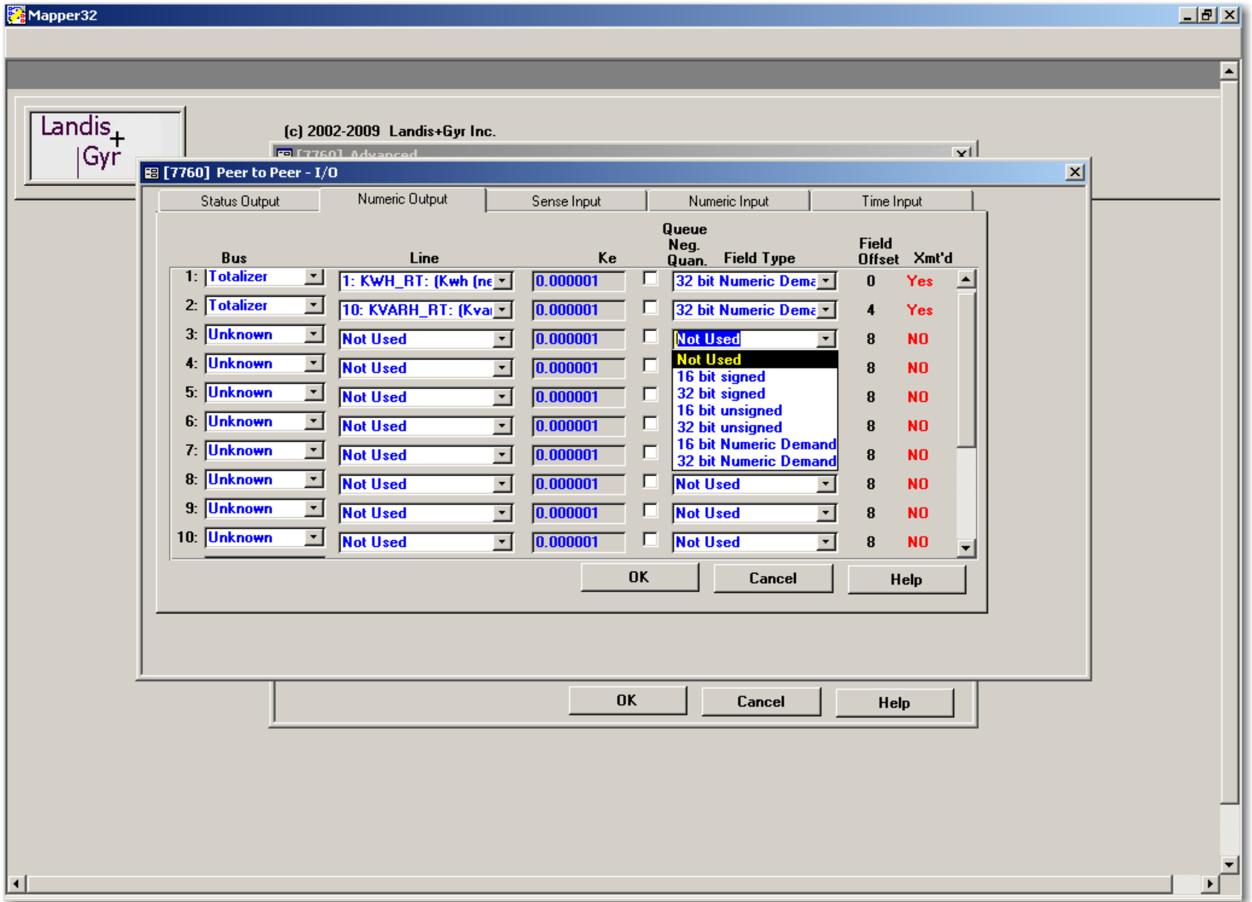
Default Program

The meter default program has been pre-configured for two (2) meters (peers 0 & 1) more can be added using Mapper32. In the default program all of the meters are putting +/- Khw and +/- Kvarh onto the peer loop and reading peers 0 and 1 back off of the communications loop. You will need to change the peer number in one of the meters when programming with MAXcom to a “1” and leave the other at “0”.



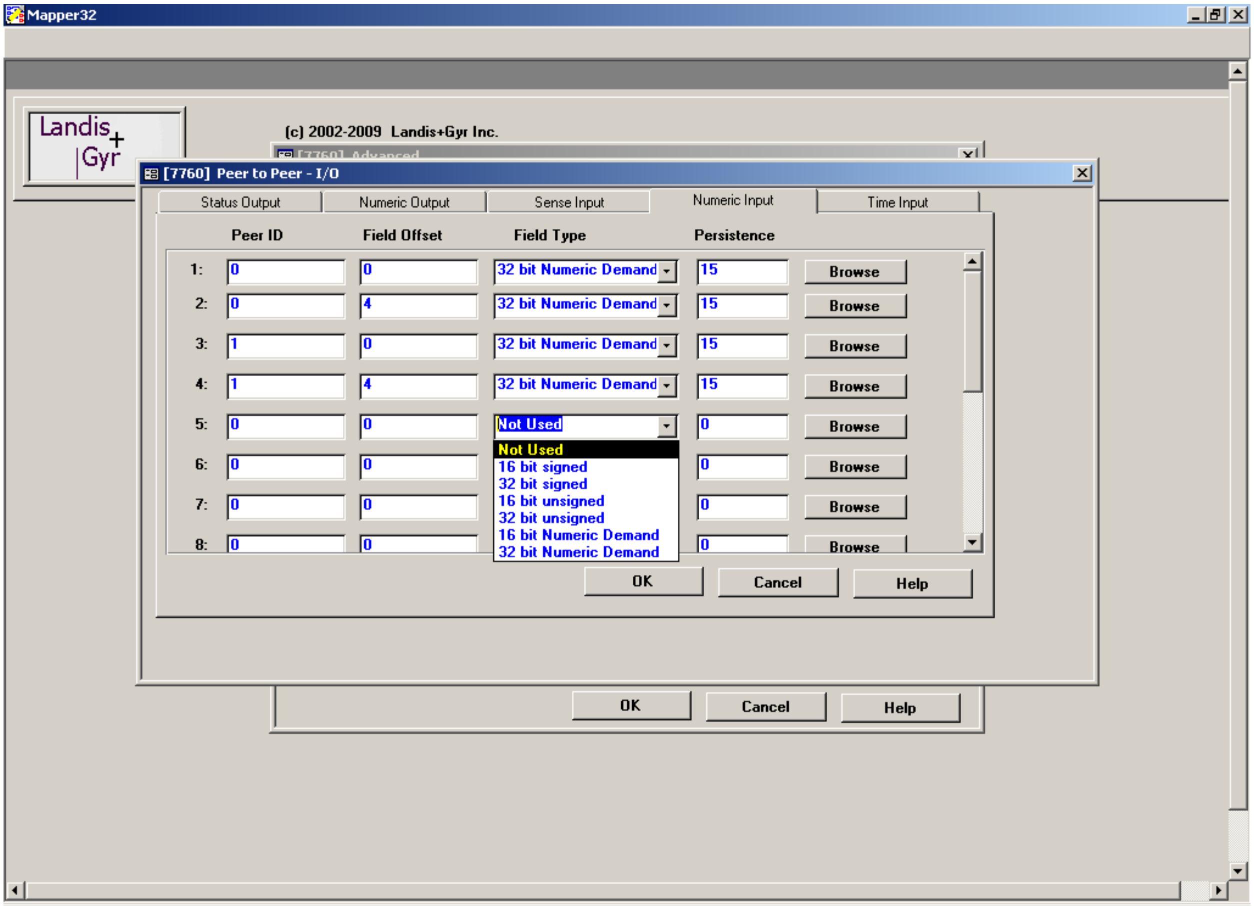
The number of meters on the loop can be increased by changing (increasing) the node count. The number of nodes can be larger than the number of meters being installed on the loop but can not be less. Status outputs could also be added. For more information see the detailed specifications at the end of this section.

This shows the two outputs that have been selected (configured).



The two outputs that have been selected in the default program are +/- Kwh and +/- Kvarh. The field type is 32 bit Numeric Demand data. The Two types of data are demand and non-demand. The demand type is normally used when the output is going to be used for analogs, instantaneous or SCADA values. When using demand type data, the value will only be sent one time if the communications fails the data will not be resent. The units reading the data knows if the read fails to reuse the last good data up to the maximun number set by the user. If non-demand data is used and the communications fails the data will be resent along with the new data. The communications can be down with this mode for upto one minute without loss of information. Depending on the application both data type can be sent.

This shows the Numeric Inputs, what will be read off of the communication loop.



The two inputs that have been selected in the default program are +/- Kwh and +/- Kvarh. The field type is 32 bit Numeric Demand data. The Two types of data are demand and non-demand. The demand type is normally used when the output is going to be used for analogs, instantaneous or SCADA values. When using demand type data, the value will only be sent one time if the communications fails the data will not be resent. The units reading the data knows if the read fails to reuse the last good data up to the maximun number set by the user. This is the persistence field. In the default the meter will reuse the old data for upto 15 reads. If non-demand data is used and the communications fails the data will be resent along with the new data. The communications can be down with this mode for upto one minute without loss of information. The input and out put types must match.

Detailed Specifications

Peer-To-Peer Network Setup

Rev D 08-25-03
This document describes the procedure for setting up a peer-to-peer network between several meters. There are three separate tasks required to define the network: First the peer outputs must be defined *for all meters in the network*, second the peer inputs must be defined, and third the communications parameters must be defined. Table 64 sets up the outputs and inputs. Table 8 also plays are part in setting up the inputs, and one of Tables 30, 31, or 32 sets up the communications depending on which port is being used.

Peer-To-Peer Output Setup

There are two types of peer outputs available today: status, and numeric. As the name implies, status outputs are binary bits. The status output source can be any logic bus/line, or the new Y and Z busses. The sense (plus or minus) of a given status output is also selectable. Up to 16 status outputs can be defined. Note that all 16 status bits are transmitted in the same word. When the status word is transmitted it is always the first word in the data packet.
Numeric outputs are more complex, and use more bandwidth than status outputs. A peer numeric output has a source, a Ke value, and a field type parameter. The sender and the receiver must agree on the field type, the Ke value, and the placement of the data in the sender's output record.
The following field types are available when sending peer numeric data:
S16 16-bit Signed
S32 32-bit Signed
U16 16-bit Unsigned
U32 32-bit Unsigned
Signed fields allow for sending data that changes direction (such as Net kWh), where unsigned fields must send data that cannot change direction (such as Delivered kWh).
The field-type and Ke value must be chosen carefully. The Ke must be large enough so that at least one-minute's worth of energy accumulation will fit in the chosen field type. The reason for this is that the peer network will try to restore the network for up to one minute when communications have been disrupted. If the network cannot be restored in less than one minute, then any pending data is lost. But, if the network is restored after say, 50 seconds, then the value to be sent will be the accumulated data in the last 50 seconds divided by the Ke value. That value must fit within the data type chosen.
The source for a peer numeric output can be any of the "type 2" busses (I, T, K, X), or the S (summation) buss.

Peer-to-peer Demand type

A demand data type has been added to the peer-to-peer protocol. Previously, The peer numeric data type have all been cumulative. That is, any received data was always added to the previous sum of received data. The peer numeric inputs did not take into account the difference in time over which the data had been accumulated by the sender. While,

all the meters in the peer network have a nominal 1.00 second energy update period, the period may vary slightly from one update to the next. For example, the sender's energy update period that produced the information out on the "wire" may have been 0.95 seconds, while the receiving meter's energy update period may be 1.05 seconds.
This time error creates large errors in the ensuing demand calculations when the peer data is finally used. The solution to this problem requires a new data type with specific characteristics that address this problem.
The new demand data type has the following features:

1. The data does not "sum". New data always replaces old data completely.
2. Demand data is "time-normalized". Prior to being transmitted, the data is scaled up or down as necessary to make it look like the energy update period was exactly one second long. The receiving meter then re-scales the input value to match its own energy update period.
3. Demand data can be made to "persist" for a programmable number of seconds. If the sender does not transmit its data, or sync is lost, or there is a network rebuild, this persistence allows the demand calculation to remain stable until real input data is restored. If the real input data remains lost for a period longer than the persistence time, then the persistence ends, and the input is set to zero. The persistence time is programmed by specifying the time in the unused Table 64 BIT_NUMBER field. Currently this field is used only by status type inputs.

Demand data is always signed, and can be 16-bits or 32-bits in length. The new field types are:

0x0A Signed 16-bit demand data
0x0B Signed 32-bit demand data

The characteristics of demand data types make them unsuitable for billing data. While over time, the data will probably match the totals for cumulative data, that is not assured. This data type is intended to allow peer-to-peer data to be used in real-time demand applications.

Peer-To-Peer Input Setup

The peer input types are mirrors of the two types of peer outputs: status, and numeric. Peer inputs are brought into the meter and made available on the 'I' buss. The numeric inputs are used in the same way that the other numeric inputs are used (such as the values on I1 through I6). The peer status inputs are appended to the status array that exists in the meter today. The first peer status input appears in the status word immediately AFTER the three phase indicators. However, the meter is limited to 16 total status inputs. That means that if any aux inputs are used as status inputs, then an equal number of peer status inputs become unavailable.
For example: There are no aux inputs defined as status inputs. As such, the meter status word is mapped as follows:

Bit 0: Phase C presence
Bit 1: Phase B presence
Bit 2: Phase A presence
Bit 3: Peer Status Input 1

Bit 4: Peer Status Input 2
Bit 5: Peer Status Input 3
Bit 6: Peer Status Input 4
Bit 7: Peer Status Input 5
Bit 8: Peer Status Input 6
Bit 9: Peer Status Input 7
Bit 10: Peer Status Input 8
Bit 11: Peer Status Input 9
Bit 12: Peer Status Input 10
Bit 13: Peer Status Input 11
Bit 14: Peer Status Input 12
Bit 15: Peer Status Input 13
For another example: There are 3 aux inputs defined as status inputs. As such, the meter status word is mapped as follows:
Bit 0: Aux Input 6
Bit 1: Aux Input 7
Bit 2: Aux Input 8
Bit 3: Phase C presence
Bit 4: Phase B presence
Bit 5: Phase A presence
Bit 6: Peer Status Input 1
Bit 7: Peer Status Input 2
Bit 8: Peer Status Input 3
Bit 9: Peer Status Input 4
Bit 10: Peer Status Input 5
Bit 11: Peer Status Input 6
Bit 12: Peer Status Input 7
Bit 13: Peer Status Input 8
Bit 14: Peer Status Input 9
Bit 15: Peer Status Input 10
Note in the above example that the last three peer status inputs are not available, because they were bumped off the end of the status word to make room for the three aux status inputs that now occupy the beginning of the status word.

Peer-To-Peer Communications Setup

Once the peer outputs and peer inputs have been defined for all meters in the network, the communication requirements become apparent. The outputs for all meters in the network must be defined first so that the total number of bytes to transfer becomes known.
Obviously, all the meters in the network must transmit at the same baud rate. However, the baud rate is not arbitrary. When a meter transmits its data, it also receives it. This effectively doubles the communications overhead during that time. In other words, a meter transmitting at 9600 baud has an apparent communication overhead of 19200 baud. Therefore, it is best to pick a baud rate that is as low as possible, but also one that allows all data to be transmitted within one update period.

To determine the baud rate required by the system, the total number of bytes transmitted must be calculated. To arrive at this value, sum up the total payload bytes of all the meters in the network. To this total add the product of the number of meters times 8 bytes of overhead data.

Once the total number of bytes is known, multiply by 10 to arrive at the number of bits to transmit. Since we wish to complete a full data cycle in less than one second (say 900 milliseconds), divide the total number of bits (which is bytes times 10) by 0.9 seconds. The result is the baud rate in bits per second required to allow every meter in the network to transmit its data within one second.

The calculated baud rate of course will not be one of the standard baud rates, so the next higher standard baud rate should be used. Using this method relieves as much overhead as possible from the meter.

An example from above is a network of three meters. Meter 1 transmits 6 bytes of payload data, Meter 2 transmits 34 bytes of payload data, and Meter 3 transmits 12 bytes of payload data. The total payload bytes are 6+34+12 = 52 bytes.

To this we must add 3 meters times 8 bytes of overhead = 24 overhead bytes. The total number of bytes transmitted in one data cycle is 76, which translates to 760 bits.

The minimum baud rate required to send those bits within 900 milliseconds is 760 bits divided by 0.9 seconds = 844.4 baud. The next standard baud rate that is higher than 844 is 1200, so the network should be set up to operate at 1200 baud.

Peer to peer communications is possible on any one of the current-loop port, the RS232-1 port, or the RS232-2 port, but only one port can be programmed for peer to peer at one time. The mode for peer-to-peer communication is 0x8003.

Note also that the number of meters in a network has an effect on the network performance. Every time a meter drops off line, or comes back on line, a network "re-build" is required. The number of meters in the network adds to the time required to accomplish the rebuild, during which time no energy data is being transferred, so even though the number of nodes can be 32, the actual number of nodes in the network should be used as "max nodes" in Table 64

Peer-To-Peer Setup Forms

There are four pages of forms below to aid in constructing a peer network. Pages A1 through A3 are filled out for each meter in the network. Page A4 is filled out once after pages A1 through A3 have been filled out for all the meters in the network.
Note that pages A1 through A3 have a space on the bottom line to fill in the meter node number to which that page belongs.

Peer Node Information Form (Page A1)

This form identifies the meter type and some general information about the network in which it is attached.
The firmware version and meter ID are on the form to help identify the meter. The node number and the number of meters identifies the size of the network and that particular meter's position in the network.

Peer Status Transmit List (Page A1)

This form identifies all the status outputs that a particular meter will transmit. The outputs must be listed contiguously, since the output list will be terminated if an invalid source, or an invalid field type is entered. All status outputs have a field type of 1.
Table 64 has an array of peer status output control structures. Use the information in the Peer Status Transmit List to fill in Table 64.
The "Output Number" is a label to help identify which Table 64 status output entry is used.
The "Output Name" is a text name to help identify what is being sent (For example 'Phase A Presence', or '50 KW threshold exceeded').
The "Source" is the buss and line where the status data is located (For example 'Y-3').
The "+/-" indicates if the output should be inverted before being transmitted. A '+' indicates no inversion, a '-' indicates inversion. If the output is to be inverted, then the 'Dwell Time' field in the Table 64 status output structure related to this output should be set to a negative value.
The "Bit Offset" indicates the bit number in the output status word that will hold this value. This information is used by the receiving meter to set up its status inputs.

Peer Numeric Transmit List (Page A2)

This form identifies all the numeric outputs that a particular meter will transmit. The outputs must be listed contiguously, since the output list will be terminated if an invalid source, or an invalid field type is entered.
Table 64 has an array of peer numeric output control structures. Use the information in the Peer Numeric Transmit List to fill in Table 64.
The "Output Number" is a label to help identify which Table 64 numeric output entry is used.
The "Output Name" is a text name to help identify what is being sent (For example 'Delivered KWh ', or 'Net Compensated KWh').
The "Source" is the buss and line where the numeric data is located (For example 'I-2', or S-10).

The “Ke” is the Ke conversion factor for the output. See the section entitled “Peer-To-Peer Output Setup” above for a discussion of how to choose a Ke value.
Here is the formula to use for arriving at a peer to peer Ke value:
Use these MAX_VALUES:
16-bit signed: MAX_VALUE = 2^15
16-bit unsigned: MAX_VALUE = 2^16
32-bit signed: MAX_VALUE = 2^31
32-bit unsigned: MAX_VALUE = 2^32
We don't want to allow an overflow to occur with stored up data, so assume a maximum of seconds of data can pile up, due to network rebuilds.
Ke = <Max_update_value> * 10 / MAX_VALUE
If the answer seems ridiculously small, maybe you should be using 16-bit data to save bandwidth on the wire.
The “Field Type” identifies the size and behavior of the numeric output field. The choices are listed at the bottom of page A2.
The “Size” field identifies the number of bytes occupied in the output record by this field. 16-bit fields occupy 2 bytes, while 32-bit fields occupy 4 bytes.
The “Byte Offset” field identifies the starting byte in the output record for this field. The byte offset is always the byte-offset + size of the *previous* output. For example if output 3 has an offset of 8, and a size of 4 bytes, then output 4’s byte offset is 12.
Note that the first line of the numeric transmit list contains the two-byte status field with a starting offset of 0, and a size of 2. If the meter transmits a status field, then the numeric output 1 will have a starting byte offset of 2. If the meter does not transmit status, then cross out the status line in the output list, and set the byte offset of numeric output 1 to 0.
After all the numeric outputs have been defined, calculate the offset of the next output *as if there is a next output*, and enter that in the line that reads “Total Data bytes transmitted by this node”. This is the number of “payload” bytes transmitted by this meter. This value is also entered on page A4 in the network summary.

Peer Status Input List (Page A3)

This form identifies all the peer status inputs that a particular meter will receive. All status inputs have a field type of 1.
Table 64 has an array of peer status input control structures. Use the information in the Peer Status Input List to fill in Table 64.
The “Input Number” is a label to help identify which Table 64 status input entry is used.
The “Input Name” is a text name to help identify what is being received (For example ‘Gen 3 Online’).
The “Source Meter Node” is the peer node number of the meter that sends this status bit.
The “Bit Offset” is the offset *within the sending meter’s status word* where this bit can be found.
The “Local ‘I’ Bus” field is an informational field that identifies which meter input on the receiving meter that this status input can be found.

Peer Numeric Input List (Page A3)

This form identifies all the peer numeric inputs that a particular meter will receive.

Table 64 has an array of peer numeric input control structures. Use the information in the Peer Status Input List to fill in Table 64. Also the Ke value from the sending meter must be installed into Table of the receiving meter at the appropriate input position.
The “Input Number” is a label to help identify which Table 64 numeric input entry is used.

The “Input Name” is a text name to help identify what is being received (For example ‘Gen 3 Phase A V2h’).
The “Meter Node” is the peer node number of the meter that sends this numeric value.
The “Ke” is the Ke conversion factor for the output. This value should be identical to the Ke value for the particular output of the sending meter. The Ke value must be entered in the receiving meter’s Table 8 for the input identified in the column “Local ‘I’ Bus”.
The “Field Type” should also be identical to the field type for the particular output of the sending meter.
The “Byte Offset” is the starting offset *within the sending meter’s output record* where this numeric value can be found.
The “Local ‘I’ Bus” field is an informational field that identifies which meter input on the receiving meter that this numeric input can be found.

Peer Network Summary (Page A4)

This form helps to determine the required baud rate for the entire network. After the Peer Numeric Transmit List has been filled out for all meters in the network, then this form can be filled out.
For each meter in the network, copy the “Total Data bytes transmitted by this node” (found on page A2) to the appropriate “Payload Bytes” column.
The “Total Payload bytes” is then just the sum of all the “Payload Bytes” entries in the above table.
The “Total ACTIVE meters in Network” is simply the number of meters that transmit data.
The “Total bytes transmitted” is the sum of the “Total Payload bytes” field plus the “Total ACTIVE meters in Network” field times 10.
The “Minimum Baud Required” field is the “Total bytes transmitted” field times 10, then divided by 0.9.
The “Actual baud” is then the lowest baud in the table that is greater than the “Minimum Baud Required” value.

Peer Node Information

Meter Firmware Version/Revision ____________________

Meter Unit ID ____________________

Node Number of this Meter ____________________

Number of Meters in Network ____________________

Peer Status Transmit List

Output Number	*Output Name*	*Source*	*+/-*	*Bit Offset*
1	____________	______	___	0
2	____________	______	___	1
3	____________	______	___	2
4	____________	______	___	3
5	____________	______	___	4
6	____________	______	___	5
7	____________	______	___	6
8	____________	______	___	7
9	____________	______	___	8
10	____________	______	___	9
11	____________	______	___	10
12	____________	______	___	11
13	____________	______	___	12
14	____________	______	___	13
15	____________	______	___	14
16	____________	______	___	15

Meter Node ________________

Peer Numeric Transmit List

Output		Field	Size	Byte		
Number	**Output Name**	**Source**	**Ke**	**Type**	**(Bytes)**	**Offset**
--	Status	--	--	STATUS	2	0
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						

Total Data bytes transmitted by this node ________

Field Type	Type codes	Description
Not Used	0	Field is not used
STATUS	1	Status bit
S16	5	16-bit signed value
S32	6	32-bit signed value
U16	7	16-bit unsigned value
U32	8	32-bit unsigned value

Meter Node______________________

Peer Status Input List

Input Number	**Input Name**	**Node**	**Bit Offset**	**Local "I" Bus**
1	______	______	______	63
2	______	______	______	64
3	______	______	______	65
4	______	______	______	66
5	______	______	______	67
6	______	______	______	68
7	______	______	______	69
8	______	______	______	70
9	______	______	______	71
10	______	______	______	72
11	______	______	______	73
12	______	______	______	74
13	______	______	______	75

Peer Numeric Input List

Input Number	**Meter Input Name**	**Field Node**	**Byte Ke**	**Local Type**	**Offset**	**"I" Bus**
1	______	______	______	______	______	36
2	______	______	______	______	______	37
3	______	______	______	______	______	38
4	______	______	______	______	______	39
5	______	______	______	______	______	40
6	______	______	______	______	______	41
7	______	______	______	______	______	42
8	______	______	______	______	______	43
9	______	______	______	______	______	44
10	______	______	______	______	______	45
11	______	______	______	______	______	46
12	______	______	______	______	______	47
13	______	______	______	______	______	48
14	______	______	______	______	______	49
15	______	______	______	______	______	50
16	______	______	______	______	______	51

Meter Node ________________

Peer Network Summary

Meter Node	Unit ID	Payload Bytes	Meter Node	Unit ID	Payload Bytes
0	_______	_______	*16*	_______	_______
1	_______	_______	*17*	_______	_______
2	_______	_______	*18*	_______	_______
3	_______	_______	*19*	_______	_______
4	_______	_______	*20*	_______	_______
5	_______	_______	*21*	_______	_______
6	_______	_______	*22*	_______	_______
7	_______	_______	*23*	_______	_______
8	_______	_______	*24*	_______	_______
9	_______	_______	*25*	_______	_______
10	_______	_______	*26*	_______	______
11	_______	_______	*27*	_______	_______
12	_______	_______	*28*	_______	_______
13	_______	_______	*29*	_______	_______
14	_______	_______	*30*	_______	_______
15	_______	_______	*31*	_______	_______

Total Payload bytes ______________ ***(Pt)***

Total ACTIVE meters in Network ______________ ***(Ma)***

Total bytes transmitted (Pt + (Ma * 10)) ______________ ***(Bt)***

Minimum Baud Required ((Bt * 10) / 0.9) ______________ ***(BAUDmin)***

Standard Baud Rates ***300, 600, 1200, 2400, 4800, 9600, 14400, 19200,28800,38400,56600,115200***

Actual Baud (from table) ________________ ***(BAUDact)***

11.11.1 Data Flow and Sample Rates for the MAXsys Meters

The following information describes in general the data flow and updating within the MAXsys metering system.

The DSP measurement systems samples at approximately 22,080 times a second (Elite meter samples at 31,250 times a second) and processes the information and hands the data over to the metering system for other calculations and register updates. The registers data is used to provide information which generally falls within the following types; Displays, Analogs, Data Recorder and Relay Outputs and SCADA data.

Meter Inputs (I-Bus), all of the meter inputs are normally updated at the end of each second; this includes both RT (real time) and the non-real time inputs. Depending on the firmware there may be both RT and None RT inputs available. All per phase values are real time values (DSP numbers). All of the non-real time inputs are updated when the accumulated change is greater than 0.0002 (granular data) for energy and therefore could go unchanged for one or more seconds depending on the load.

Displays: In general all of the displays can update at the end of each second depending on the type of display.

a. Energy Registers (Values ending in “H” hours), the amount of energy measured for the previous second is summed and update at the end of each second. Therefore the values for all energy registers update every second. Note this is the same data register that could be supplied data to the SCADA outputs.
b. Counter Registers (The number of events), the counters are also updated at the end of each second. Therefore if the meter was counting the number of breaker operations the number would update at the end of each second. Therefore the count would be correct at the end of each second. Note this is the same data register that could be supplied data to the SCADA outputs.
c. Demand Registers (Maximum, Minimum, Concurrent and Last interval), are updated at the end of each demand subinterval. Note this is the same data register that could be supplied data to the SCADA outputs.
d. Instantaneous Registers (There can be three types of instantaneous registers depending of the firmware), Instantaneous RT (real time), Instantaneous and instantaneous filtered in some version of firmware. Note this is the same data register that could be supplied data to the SCADA outputs.
    a. The instantaneous RT values normally update at the end of each second, providing a one second value that updates every second. (See exceptions)
    b. The instantaneous (none real time) value is a one minute running average that updates every 10 seconds.
    c. The instantaneous filtered value is an average based on the filter that is user controlled. If the filter was set to 5 seconds. The value would be a 5

second average that updated every second. (Only available in firmware 57xx or 7760).

Analog Outputs: In general all of the analog outputs can update at the end of each second depending on the type of instantaneous value that is selected.

a. Analog Outputs are normally driven by the instantaneous registers that were described under instantaneous registers. The exception is the analog outputs also have a filter that is user controlled to make other averages.

Data Recorders: In general all of the data recorders update at the end of each recorder interval.

a. Recorder Channels are normally driven by the same inputs that are used for energy registers.

Relay Outputs: In general outputs can update at the end of each second.

a. Relay Outputs are normally driven by the same inputs that drive energy registers. The exception is the relay is used as an event or threshold relay. Example, the amount of energy that was measured for the last second is divided by the output relay Ke value and then the correct number of pulses are generated and any value less than a pulse is carried over and summed into the next second.

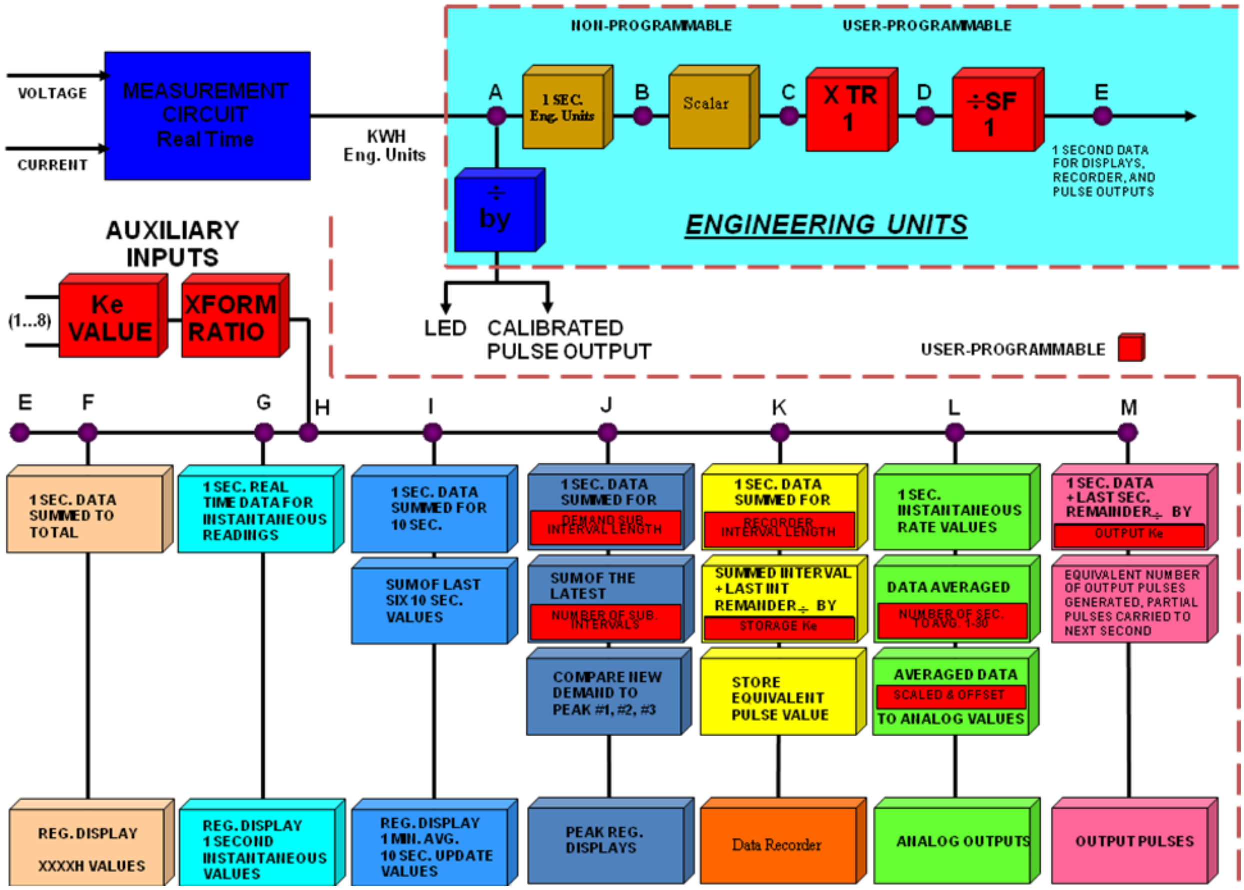
SCADA Outputs: In general all SCADA registers are update at the end of each second.

a. SCADA Outputs are normally driven by the same registers that drive the displays.

Exceptions by firmware:
2747 and 2753 do not have user defined filters and the instantaneous values normally update every 2 seconds. All of the inputs are RT (real time) except for the 3-phase values and inputs that are connected to the auxiliary pulse inputs. All per-phase values are RT (real time).

2751, 2752 do not have user defined filters and the instantaneous values normally update every second. All of the inputs are RT (real time) except for the 3-phase values and inputs that are connected to the auxiliary pulse inputs. All per-phase values are RT (real time).

5759 and 7760 have user defined filters and the instantaneous values normally update every second. All of the inputs are RT (real time) except when pulses are connected to the auxiliary pulse inputs.



NON-PROGRAMMABLE
USER-PROGRAMMABLE
VOLTAGE
CURRENT
MEASUREMENT CIRCUIT Real Time
KWH Eng. Units
A
1 SEC. Eng. Units
B
Scalar
C
X TR 1
D
÷SF 1
E
1 SECOND DATA FOR DISPLAYS, RECORDER, AND PULSE OUTPUTS
÷ by
ENGINEERING UNITS
LED
CALIBRATED PULSE OUTPUT
AUXILIARY INPUTS
(1...8)
Ke VALUE
XFORM RATIO
USER-PROGRAMMABLE
E
F
G
H
I
J
K
L
M
1 SEC. DATA SUMMED TO TOTAL
1 SEC. REAL TIME DATA FOR INSTANTANEOUS READINGS
1 SEC. DATA SUMMED FOR 10 SEC.
1 SEC. DATA SUMMED FOR DEMAND SUB. INTERVAL LENGTH
1 SEC. DATA SUMMED FOR RECORDER INTERVAL LENGTH
1 SEC. INSTANTANEOUS RATE VALUES
1 SEC. DATA + LAST SEC. REMAINDER ÷ BY OUTPUT Ke
SUM OF LAST SIX 10 SEC. VALUES
SUM OF THE LATEST NUMBER OF SUB. INTERVALS
SUMMED INTERVAL + LAST INT REMAINDER ÷ BY STORAGE Ke
DATA AVERAGED NUMBER OF SEC. TO AVG. 1-30
EQUIVALENT NUMBER OF OUTPUT PULSES GENERATED, PARTIAL PULSES CARRIED TO NEXT SECOND
COMPARE NEW DEMAND TO PEAK #1, #2, #3
STORE EQUIVALENT PULSE VALUE
AVERAGED DATA SCALED & OFFSET TO ANALOG VALUES
REG. DISPLAY XXXXH VALUES
REG. DISPLAY 1 SECOND INSTANTANEOUS VALUES
REG. DISPLAY 1 MIN. AVG. 10 SEC. UPDATE VALUES
PEAK REG. DISPLAYS
Data Recorder
ANALOG OUTPUTS
OUTPUT PULSES