1.1 INTRODUCTION

This Annual Plan is based on the July 2011 Design Forecast of receipts and deliveries for the Alberta System. An overview of the July 2011 Design Forecast was presented at the November 22, 2011 TTFP meeting.

Information on forecasting methodology can be found in the Facilities Design Methodology Document Section 4.4 – Design Forecast Methodology which can be accessed online at:

http://www.transcanada.com/customerexpress/5133.html

In this section, NGTL describes the:

- economic assumptions used in developing the 2011 Design Forecast;
- receipts and deliveries for the Alberta System; and
- supply contribution, including winter withdrawal, from Storage Facilities used in the design process.

1.2 ECONOMIC ASSUMPTIONS

1.2.1 General Assumptions

The following assumptions, developed in January 2011, concern broader trends in the North American economy and energy markets, and underlie the forecast of receipts and deliveries:

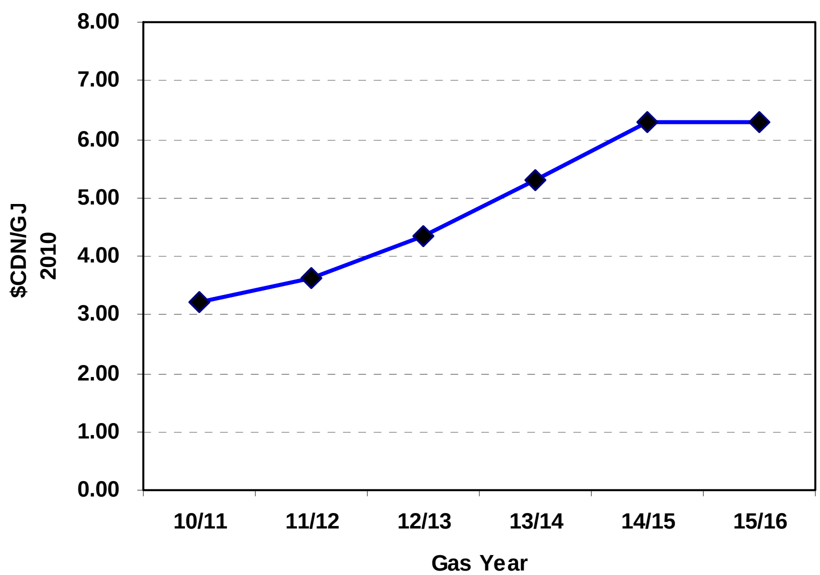
- North American natural gas demand will slowly increase in the short term as the U.S. and Canadian economies recover. In the longer term, gas demand is expected to increase with continued economic and population growth in both the U.S. and Canada. U.S. gas demand growth is predominantly associated with increased gas-fired electricity generation. Western Canadian industrial gas demand is expected to grow significantly, driven by the gas needs of the oil sands.

- The North American market will be well supplied with domestic natural gas because of the strength in unconventional gas production, primarily shale gas. This strong supply growth is now expected to be able to keep pace with the growth in gas demand, greatly reducing the volume of imported liquefied natural gas (LNG) required to balance the continental market.
- Because of weakness in natural gas demand from the slow pace of economic recovery, and the rapid expansion of shale gas supplies, short-term gas prices are expected to be soft. This is expected to be temporary as present prices are below the full cycle supply costs of most gas sources. Although a NYMEX gas price level of $6.75/MMBtu in Real 2010 $US by 2015 is more than sufficient to encourage development of unconventional shale gas resource, conventional gas is also required to meet increasing demand. NYMEX natural gas prices are forecast to recover over the next few years as the economy and gas demand improve. This higher price allows additional volumes of conventional gas to be produced, in conjunction with unconventional shale gas, to meet market demands. The gas price forecast rises from today's prices to reach an equilibrium price of $US 6.75/MMBtu in real 2010 $US by 2015.
- Currently, low gas prices are putting pressure on producers to be efficient and cost-effective. Recent drilling successes in many shale and tight gas plays have led to more fracture stages, higher initial production rates, and increases in the estimated ultimate recovery (EUR) per well, resulting in a lower cost per well for producers. These improvements have led to additional shale and tight gas resources being economic to produce in a low gas price environment, edging out higher cost conventional supply. However, even with strong growth in shale and tight gas production, there continues to be a need for a significant proportion of supply from conventional resources to meet North American gas demand requirements.

1.2.2 Alberta Average Field Price

TransCanada's NYMEX gas price forecast was used to develop the Alberta Average Field Price (Alberta Reference Price), which represents the estimated price of natural gas at a point just prior to receipt onto the Alberta System. The gas price forecast, shown in Figure 1-1, was developed in January 2011 and reflects the general assumptions from Section 1.2.1.

Figure 1-1: NGTL Gas Price Forecast, Alberta Average Field Price



The Alberta Average Field Price is forecast to rise from $3.22 Cdn/GJ to the long term equilibrium price of $6.30 Cdn/GJ (in real 2010 $) by 2015.

The gas price forecast affects the receipt and delivery forecast, and is used as input into the economic analysis for new facilities. The level of the gas price affects anticipated producer activity to support continuing production from connected supplies, connection of unconnected reserves, and the discovery and development of new reserves.

1.3 GAS DELIVERY FORECAST

Deliveries to markets within Alberta are forecast to rise, due primarily to industrial demand in the Oil Sands region. Gas demand from Oil Sands-related projects is influenced by factors such as the amount of oil produced, the price of oil and gas, the process used to produce oil, and the technological improvements employed over time. At major Border Points, contract demand and throughput have declined over the past few years, the result of changing market conditions and the ability of downstream markets to access alternative supply sources, all of which contribute to uncertainty in the gas delivery forecast.

Several sources of information were considered in developing the gas delivery forecast. First, operators of downstream facilities, such as connecting pipelines, local distribution companies (LDCs), and industrial plants, were requested to provide a forecast of their maximum, average, and minimum requirements for deliveries from the Alberta System over the next ten years. The forecasts were analyzed and compared to historical flow patterns at Alberta Delivery Points. In cases where NGTL's analysis differed substantially from the operator's forecast, NGTL contacted the operator and either the operator's forecast was revised or NGTL adjusted its analysis. In cases where the operator did not provide a forecast, NGTL based its forecast on historical flows and growth rates for specific demand sectors.

1.3.1 Average Annual Delivery Forecast

The Average Annual Delivery forecast is the forecast aggregate deliveries for the Alberta System for the 2011/12 through 2015/16 Gas Years. Forecast deliveries by

Gas Year are expressed as an average daily flow and are listed by Delivery Point in Table 1-1. Alberta deliveries are further detailed by Project Area in Table 1-2.

Table 1-1: System Average Annual Delivery Forecast by Delivery Point

Delivery Point	July 2011 Design Forecast (10^6m^3/d)				
	2011/12	2012/13	2013/14	2014/15	2015/16
Empress	90.0	100.6	108.5	116.4	121.2
McNeill	43.8	42.9	44.4	45.5	45.5
Alberta/B.C.	49.6	48.3	51.5	56.8	60.7
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	1.0	1.0	1.0	1.0	1.0
Cold Lake	0.8	0.8	0.8	0.8	0.8
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	0.7	0.7	0.7	0.7	0.7
Intra Alberta	112.2	118.5	123.9	131.6	138.2
Total System	**298.1**	**312.8**	**330.8**	**352.8**	**368.1**
Delivery Point	**July 2011 Design Forecast (Bcf/d)**				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Empress	3.18	3.55	3.83	4.11	4.28
McNeill	1.55	1.51	1.57	1.61	1.61
Alberta/B.C.	1.75	1.71	1.82	2.00	2.14
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	0.03	0.03	0.03	0.04	0.04
Cold Lake	0.03	0.03	0.03	0.03	0.03
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	0.02	0.02	0.02	0.02	0.02
Intra Alberta	3.96	4.18	4.37	4.65	4.88
Total System	**10.52**	**11.03**	**11.67**	**12.46**	**13.00**

Note:
Numbers may not add due to rounding.
Volumes expressed as an average daily flow for each Gas Year, at 101.325 kPa and 15°C.

Table 1-2: Alberta Deliveries – Average Annual Delivery Forecast by Project Area

Project Area	July 2011 Design Forecast ($10^6 m^3/d$)				
	2011/12	2012/13	2013/14	2014/15	2015/16
Peace River	2.1	2.1	2.1	2.4	2.7
North and East	75.5	81.3	86.8	93.5	98.7
Mainline	32.0	32.4	32.3	33.0	34.1
Gas Taps	2.6	2.6	2.7	2.7	2.7
Total Alberta	**112.2**	**118.5**	**123.9**	**131.6**	**138.2**
Project Area	**July 2011 Design Forecast (Bcf/d)**				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Peace River	0.07	0.07	0.07	0.08	0.09
North and East	2.67	2.87	3.06	3.30	3.49
Mainline	1.13	1.15	1.14	1.17	1.20
Gas Taps	0.09	0.09	0.09	0.10	0.10
Total Alberta	**3.96**	**4.18**	**4.37**	**4.65**	**4.88**

Note:
Numbers may not add due to rounding.
Volumes expressed as an average daily flow for each Gas Year.
Gas taps are located in all areas of the province.

1.3.2 Maximum Day Delivery Forecast

Peak deliveries (Maximum Day Delivery) are also forecast for the Alberta Delivery Points and are based on customer input, market conditions, firm transportation contracts and historical flows.

A summary of the July 2011 Design Forecast Maximum Day Delivery by Project Area for Alberta Deliveries is provided in Table 1-3 for winter and Table 1-4 for summer.

Table 1-3: Winter Maximum Day Delivery Forecast

Project Area	July 2011 Design Forecast ($10^6m^3/d$)				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Peace River	6.3	6.3	6.4	6.8	7.3
North and East	122.6	131.8	138.6	146.9	155.1
Mainline	68.0	68.9	69.9	70.6	72.0
Gas Taps	5.1	5.2	5.3	5.3	5.3
Total Alberta	**202.0**	**212.3**	**220.1**	**229.6**	**239.7**
Project Area	**July 2011 Design Forecast (Bcf/d)**				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Peace River	0.22	0.22	0.23	0.24	0.26
North and East	4.33	4.65	4.89	5.18	5.47
Mainline	2.40	2.43	2.47	2.49	2.54
Gas Taps	0.18	0.18	0.19	0.19	0.19
Total Alberta	**7.13**	**7.49**	**7.77**	**8.11**	**8.46**

Note:
Numbers may not add due to rounding.
Gas taps are located in all areas of the province.

Table 1-4: Summer Maximum Day Delivery Forecast

Project Area	July 2011 Design Forecast ($10^6m^3/d$)				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Peace River	6.0	6.1	6.1	6.5	7.0
North and East	122.4	131.5	138.2	146.4	154.4
Mainline	64.8	65.7	66.7	67.5	68.9
Gas Taps	2.4	2.4	2.5	2.5	2.5
Total Alberta	**195.6**	**205.7**	**213.5**	**222.9**	**232.9**
Project Area	**July 2011 Design Forecast (Bcf/d)**				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Peace River	0.21	0.21	0.22	0.23	0.25
North and East	4.32	4.64	4.88	5.17	5.45
Mainline	2.29	2.32	2.36	2.38	2.43
Gas Taps	0.08	0.09	0.09	0.09	0.09
Total Alberta	**6.91**	**7.26**	**7.54**	**7.87**	**8.22**

Note:
Numbers may not add due to rounding.
Gas taps are located in all areas of the province.

1.4 RECEIPT FORECAST

NGTL develops its Receipt Forecast on an average annual basis and uses the following general approach:

- For conventional production, NGTL typically uses an internal pool-based forecasting model that incorporates established reserve estimates and actual production records from government sources. For discovered resources, the model uses current production rates and reservoir modelling, supplemented by internal analysis to estimate future production. In order to estimate the future supply from undiscovered resources, NGTL bases its assessment on play and pool-based resource estimates.
- For unconventional resources such as shale gas, NGTL typically uses well-based forecasting methods and models, supplemented with information gathered from customers, to generate forecasts of future production. Factors such as the total number of drilling locations available, well production profiles, and pace of development are considered along with material and equipment availability, potential capital requirements, and access constraints when developing a forecast of supply.

Exploration activity focused on unconventional gas has resulted in an expectation of significant incremental volumes of shale and tight gas entering the Alberta System in the Peace River Project Area in the near future. Incremental shale and tight gas supply is expected to offset declines in production from connected established reserves, resulting in an increase in overall production levels in the WCSB over the next five years.

Three major sources of gas supply used for the July 2011 Design Forecast included:

- Connected and Unconnected Reserves – supply from established conventional and unconventional reserves upstream of Receipt Points;

- Reserve Additions – supply from undiscovered resources, including conventional and unconventional resources; and
- Interconnections – supply from interconnections with other pipeline systems.

Gas supplied from storage facilities has not been included in the data presented in this section. Information pertaining to gas supply from Commercial Storage Facilities is contained in Section 1.6.

1.4.1 Average Receipt Forecast

The Average Receipt Forecast is the forecast aggregate receipts for the Alberta System for the 2011/12 through 2015/16 Gas Years. A summary of System Average Receipts by Gas Year and Project Area is expressed as an average daily flow and shown in Table 1-5.

Table 1-5: System Average Receipts

Project Area	July 2011 Design Forecast ($10^6m^3/d$)				
	2011/12	2012/13	2011/12	2014/15	2011/12
Peace River	138.9	155.5	172.2	193.3	212.1
North and East	27.7	26.2	26.4	28.2	27.8
Mainline	130.6	130.7	130.3	130.5	126.9
Total System	297.2	312.3	328.9	352.0	366.7
Project Area	**July 2011 Design Forecast (Bcf/d)**				
	2011/12	**2012/13**	**2011/12**	**2014/15**	**2011/12**
Peace River	4.90	5.48	6.08	6.82	7.49
North and East	0.98	0.92	0.93	1.00	0.98
Mainline	4.61	4.61	4.60	4.61	4.48
Total System	10.49	11.02	11.61	12.43	12.95

Note:
Numbers may not add due to rounding.

1.5 SUPPLY DEMAND BALANCE

Supply received on the Alberta System is balanced with System deliveries (net of gas in storage). System deliveries by destination are shown in Figure 1-2, while System receipts by Project Area are shown in Figure 1-3.

Figure 1-2: System Deliveries by Destination

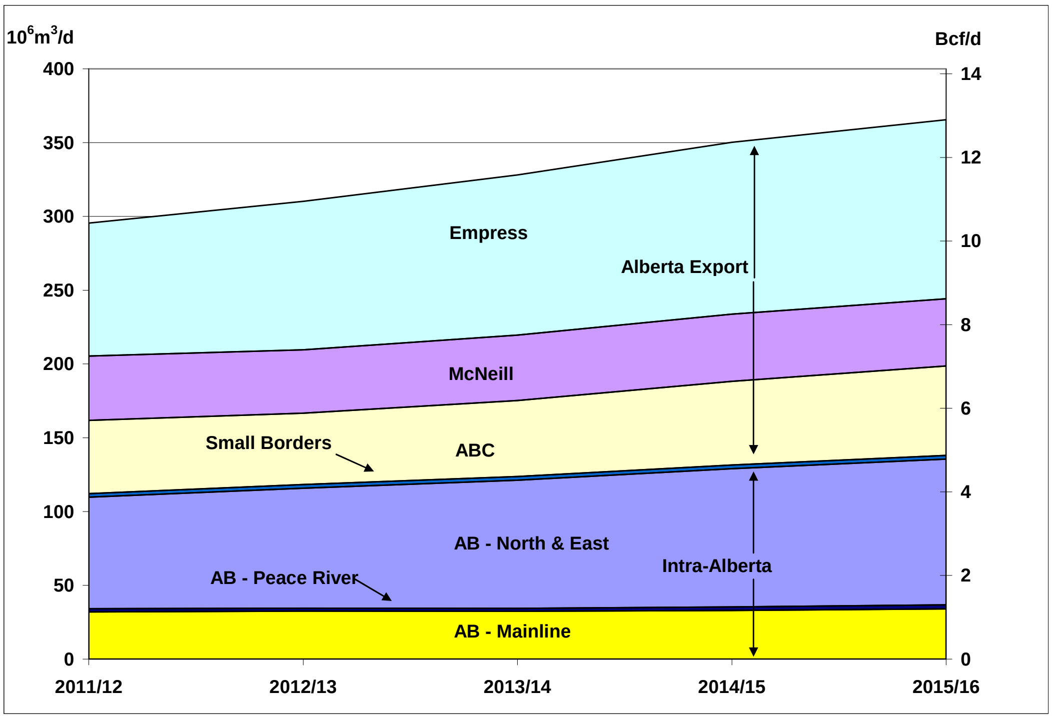
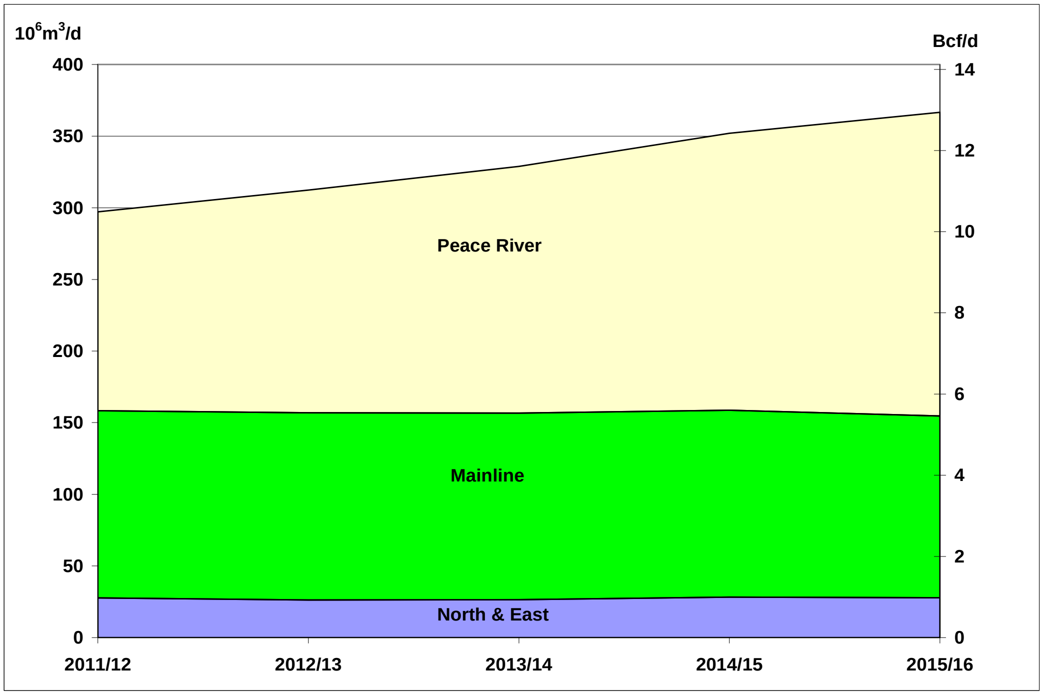


Figure 1-3: System Receipts by Project Area



1.6 STORAGE FACILITIES

1.6.1 Commercial Storage

There are eight commercial storage facilities connected to the Alberta System (AECO 'C', Big Eddy, Carbon, Chancellor, Crossfield East #2, January Creek, Severn Creek and Warwick Southeast Meter Stations). The total deliverability from Storage Facilities is significant, but actual maximum day receipts from storage are dependent upon a number of factors, including market conditions, the level of working gas in each storage facility, compression power at each Storage Facility, and Alberta System operations.

For design purposes, a supply contribution from Storage Facilities is used to meet peak day winter delivery requirements and provide for a better correlation between forecast design flow requirements and historical actual flows for the winter period. Historical withdrawals during recent winter periods at AECO 'C', Carbon, Crossfield East, Chancellor and Severn Creek were used to determine a reasonable expected rate of withdrawal for future winter seasons. The level of commercial storage withdrawal used in the design of the Alberta System for the winter season was 17.7 $10^6m^3/d$ (630 MMcf/d), which is similar to the average winter withdrawal rate from these facilities.

The receipt meter capacity for each of the connected Commercial Storage Facilities is shown in Table 1-6.

Table 1-6: Receipt Meter Capacity from Commercial Storage Facilities

Storage Facility	Receipt Meter Capacity from Commercial Storage Facilities – 2011/12	
	$10^6m^3/d$	Bcf/d
AECO C	50.7	1.79
Big Eddy	35.4	1.25
Carbon	13.8	0.49
Chancellor	35.2	1.24
Crossfield East #2	14.1	0.50
January Creek	14.1	0.50
Severn Creek	5.6	0.20
Warwick Southeast	6.1	0.22
Total	**175.0**	**6.18**

Note:
Storage is currently considered as an interruptible supply source.
Numbers may not add due to rounding.

1.6.2 Peak Shaving Storage

The Fort Saskatchewan Salt Caverns comprise a peak shaving Storage Facility in the Greater Edmonton Area within the North of Bens Lake Design Area of the Alberta System. Similar to Commercial Storage Facilities, the total deliverability from the peak shaving Storage Facility is significant, but the actual maximum day receipt from storage is dependent upon a number of factors, including market conditions, the level of working gas, compression power at the storage facility, and Alberta System operations.

For design purposes, a maximum withdrawal rate of 6,500 10^3m^3/d was used to meet the peak expected winter season delivery requirements.