Pratt II Conference
"Petroleum Provinces of the 21st Century"
January 12-15, 2000
San Diego, California

New Frontiers for Hydrocarbon Production in the Timan-Pechora Basin, Russia

Bret J. Fossum
William J. Schmidt
David A. Jenkins[1]
Conoco, Inc
Houston, Texas, USA

Vladimir I. Bogatsky
Timan-Pechora Scientific Research Center
Ukhta, Komi Republic, Russia

Boris I. Rappoport
OAO Arkhangelskgeoldobycha
Arkhangelsk, Nenets Okrug, Russia

ABSTRACT

The Timan-Pechora Basin, located west of the Ural Mountains in northern Russia, is a prolific oil province covering 300,000 square kilometers. The basin, which has been efficiently explored, is predominantly oil prone but significant accumulations of gas exist.

The mean discovered field size of the basin has diminished considerably since first explored in the 1930s. Onshore, the current exploration potential is small to moderate in terms of potential field reserves size but large in terms of number of untested prospects and leads. Eight of the nine identified plays have been characterized in the plateau phase. The remaining play is in breakthrough phase but the reserves potential is small to moderate. The field development potential of the onshore region is substantial. Overall, 80% or 13 billion barrels of oil reserves remain unproduced. Most of the unproduced oil reserves are found in three carbonate plays of Lower Permian, Upper Devonian Fammenian and Lower Devonian age.

Exploration potential exists in the offshore Pechora Sea, which is an immature exploration region. Four main plays, extensions of proven plays within the onshore portion of the basin, define the offshore exploration potential. The offshore portions of the plays are in active growth or possibly breakthrough phase.

---

[1]Presenter

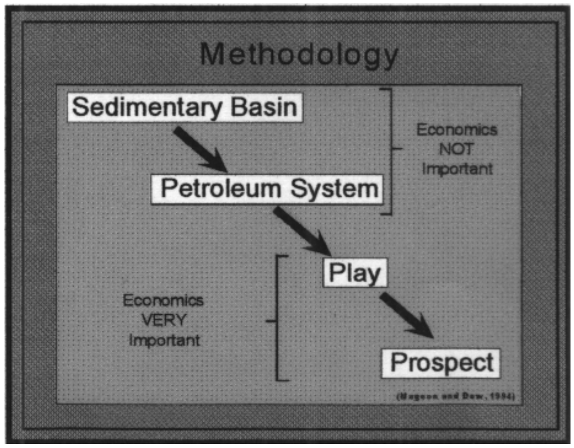

Figure 1. *Outline of methodology.*

INTRODUCTION

Methodology for the Timan-Pechora Basin evaluation presented in this paper was based on petroleum system investigation principles from Magoon and Dow (1994). Figure 1 summarizes the approach.

Four levels of petroleum investigations exist and include:

1. *Sedimentary basin* investigations that emphasize the stratigraphic sequence and structural style of sedimentary rocks.
2. *Petroleum system* studies that describe the genetic relationship between a pod of active source rock and the resulting oil and gas accumulations. Also known as the source rock - reservoir couplet.
3. Investigations of *plays* that describe the present-day similarity of a series of present-day traps.
4. Studies of *prospects* that describe the individual present day trap.

Economic considerations are not important in *sedimentary basin* and *petroleum system* investigations, but are essential in *play* and *prospect* investigations.

This paper will describe primarily *the sedimentary basin, petroleum system* and play aspects of the oil resources in the Timan-Pechora Basin. Gas is perceived to have minimal value in much of the basin at the present time however the reserves are substantial (37 Tcfg). Accordingly, the abundant coal and coal-bed methane resources in the basin will not be addressed. The hydrocarbon resource economic criteria are also beyond the scope of the present paper.

Political boundaries are important in the Timan-Pechora Basin, since governing bodies and laws vary for each region (Figure 2). The Nenets Autonomous Okrug to the north and the Komi Republic to the south regulate the onshore portion of the basin. The Permian Oblast, located in the extreme southern portion of the basin, holds minimal reserves and will not be discussed in this paper. The Murmansk District regulates the Pechora Sea.

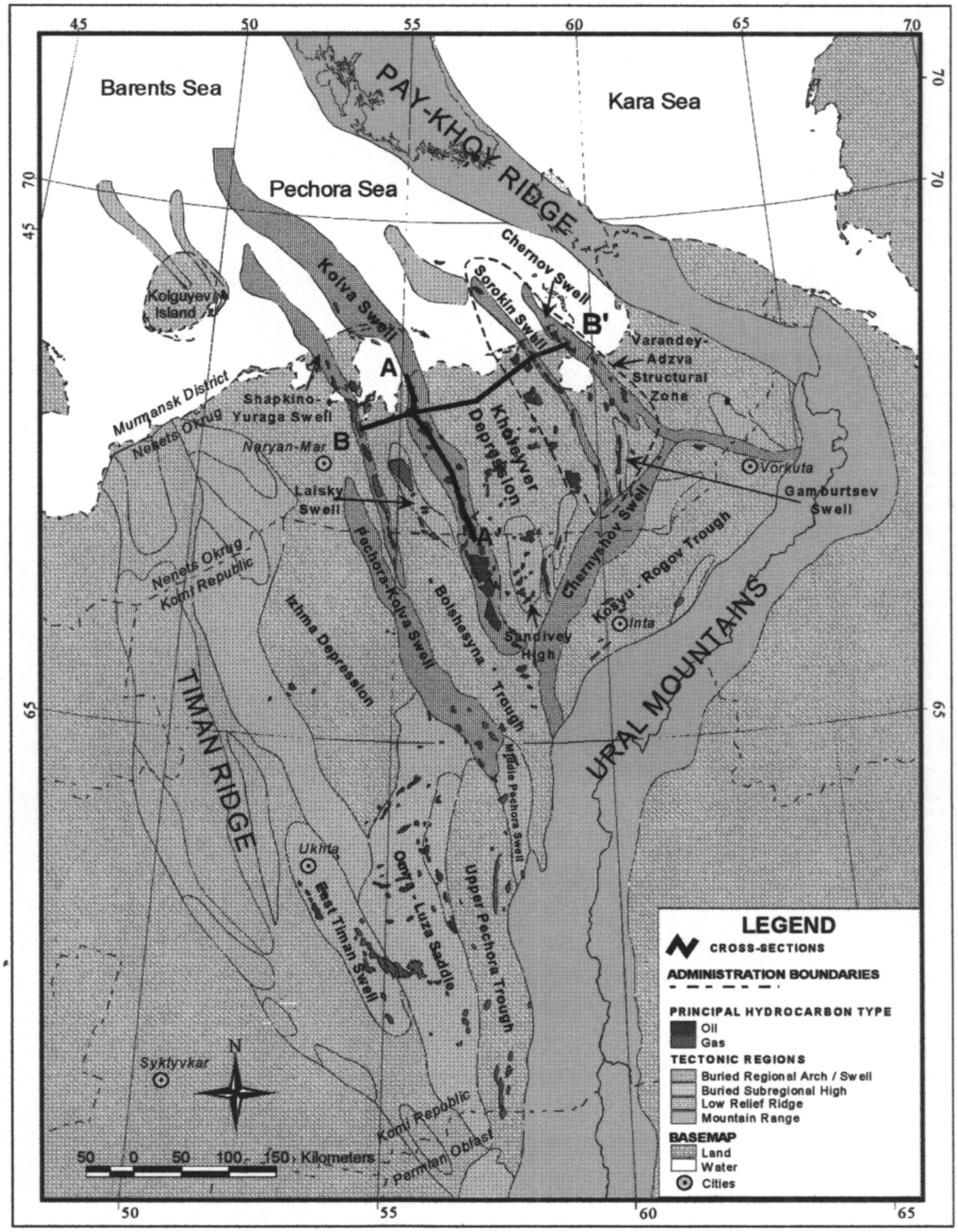

Figure 2. *Timan-Pechora Basin structural features, political provinces and cross-section locations.*

DEFINITIONS

For this discussion, the following abbreviations are used:

1. Reserves - Recoverable hydrocarbons.
2. EUR - Estimated ultimate recovery. Includes produced, proved, and probable reserves.
3. Mmbo - Million barrels of oil.
4. Mmbc - Million barrels of condensate.
5. Mmboe - Million barrels of oil equivalent. Gas is converted to oil at a ratio of 6,000 cubic feet per barrel.
6. Bcfg - Billion cubic feet of gas.
7. Tcfg - Trillion cubic feet of gas.
8. Bopd - Barrels of oil per day
9. FSD - Field-size distribution, determined from log-normal distributions of EUR field-size values. Field-size distribution values include P90 (90% of the values have a probability of being equal to or less than this value), P50 (median value of the distribution), P10 (10% of the values have a probability of being equal to or less than) and Mean (probability weighted average or geometric mean of log-normal distribution).

BASIN BACKGROUND

Exploration History

The first stage of organized exploration in the Timan-Pechora Basin began in 1929 with the formation of a large geological field team in Ukhta, Komi Republic (Aminov et al, 1993). In the following year, the team made the first onshore hydrocarbon discovery at Chibyu (EUR 4 Mmbo) located adjacent to Ukhta (Figure 2). The first stage of exploration was completed by 1960, with the discovery of a group of oil and gas fields near Ukhta. The main hydrocarbon bearing interval in the group of fields was the Middle Devonian and Upper Devonian Frasnian clastics. The next stage of exploration, from 1960 through 1983, focused on the entire basin, including Kolguyev Island (Figure 2) in the Pechora Sea (Aminov et al, 1993). During this period, numerous oil and gas fields were discovered. Significant discoveries included Usa (EUR 1,610 Mmbo) in 1963 and Vuktyl (EUR 14.7 Tcfg and 515 Mmbc) in 1964. Usa and Vuktyl are the largest oil and gas fields respectively in the onshore portion of the basin. The Peschano-Ozer field (EUR 126 Mmbo and 117 Bcfg) located on Kolguyev Island was discovered in 1982.

The third phase of exploration occurred from 1983 to 1991 and focussed in the onshore northern Nenets Okrug region and partially in the Pechora Sea. Significant discoveries were made in the Khoreyver Depression, Kolva Swell and Varandey-Adzva Structural Zone regions (Figure 2). The first offshore discovery was made at Pomoroskoye (EUR 698 Bcfg) in 1985. Prirazlomnoye (EUR 609 Mmbo), the largest oil field in the Pechora Sea was discovered in 1989. Ardalin, the northern-most continuously producing field, was discovered in 1988. Since 1991, exploration activity in the Timan-Pechora Basin has been low.

Summarizing, oil is the main hydrocarbon phase discovered in the Timan-Pechora Basin (approximately 68% oil versus 32% equivalent gas reserves), but significant accumulations of gas exist which are mostly associated with the foredeep region that flanks the Ural Mountains and Pay-Khoy Ridge. Other significant accumulations of gas exist in the northwest Shapkino-Yuraga and Laisky Swells (Figure 2). The principal oil bearing regions are in the central and northern portion of the basin in the Kolva Swell, Khoreyver Depression and Varandey -

Adzva Structural Zone (Figure 2). Approximately 230 oil and gas fields, ranging in size from 1 Mmboe to 2,965 Mmboe (Vuktyl), have been discovered in the Timan-Pechora Basin.

Geomorphology

The geomorphology of the Timan-Pechora Basin is diverse. The northern part of the basin is situated in mostly swampy lowland with some marginal ridges known as the Malozemelsk (small land) and Bolshezemelsk (large land) Tundra. Thick permafrost tends to underlie these areas. The southern part of the basin is more elevated and extends mainly along the valley of the Pechora River, where permafrost is absent or developed locally in restricted areas.

Geomorphological features and biological species are important criteria considered in the positioning of pipelines, well drilling operations and production facilities. Barringer (1998) discusses critical elements for the northern Kolva Swell region, located in the northern onshore portion of the basin.

Infrastructure

Infrastructure in the Timan-Pechora Basin is comprised of an oil and gas pipeline gathering system and oil refinery located in Ukhta, Komi Republic. The oil refinery and gas processing plant are operational. The Usinsk - Ukhta oil pipeline (Figure 3) transports ‘domestic blend’ oil predominantly from the Usa, Kharyaga and Ardalin fields, located in the central Nenets Okrug to refineries in the south at Yaroslov, Kirishi and Moscow. The oil is then transported to the west to Baltic Sea export points in the cities of Primorsk and Porvoo. The capacity of the Usinsk - Ukhta pipeline is 330,000 bopd, Ukhta - Yaraslov 400,000 bopd, and Yaraslov - Kirishi 430,000 bopd. The Kharyaga - Usinsk pipeline, completed in September 1999 will provide for transportation to the south of 200,000 - 240,000 bopd from fields of the Nenets Autonomous Okrug (Borovinskikh, 1998).

Market access and increased export capacity are main concerns in developing fields in the Nenets Okrug. Due to the Ukhta pipeline being at or near capacity, three other transportation concepts have been suggested:

1. Reconstruction of Kharyaga - Usinsk - Ukhta pipeline, which involves increasing the pipeline capacity,
2. Construction of a new Kharyaga to the Primorsk (Gulf of Finland) oil pipeline or,
3. Construction of an offshore terminal near the Varandey or Khilchuyu fields (Nevel, personal communication, 1999). Figure 4 illustrates two possible locations for Pechora Sea offshore single point mooring terminals.

GEOLOGIC SETTING

Stratigraphy and Basin Fill

Figure 5 summarizes the stratigraphy and major tectonic events in the Timan-Pechora Basin. The sedimentary fill of the Timan-Pechora Basin was dominated by tectonic controls, which in turn determined the volume, fill, texture and composition of detrital influx. Secondary controls such as global sea level and climate were most pronounced during episodes of reduced terrigenous supply. The fundamental Late Paleozoic restructuring from passive margin to foreland basin is reflected in contrasting sedimentary composition and depositional styles below and above this boundary, which is marked by a change from platform carbonates to siliciclastics (Ressetar et al, 1997).

Figure 3. *Existing pipeline infrastructure.*

The lower, carbonate dominated interval of Ordovician to Middle Permian age developed on a passive margin or back-arc basin setting subjected to variations in eustatic sea level, tectonic subsidence, and sediment supply. Platform carbonates and mature, quartzose, fluvial-to-shelf sands grade eastward into outer shelf, slope and basinal mudstones and turbidite sandstones (Ressetar et al, 1997).

In contrast, the upper foreland basin interval reflects primarily tectonically driven base-level changes and fluvially derived sediment influx. These primarily siliciclastic sediments were derived from the Ural thrust belt from the east and were rapidly deposited in alluvial-fan, fluvial, and deltaic environments. These sandstones are typically immature except where reworked by marine processes seaward of the subaerial delta margins (Ressetar et al, 1997).

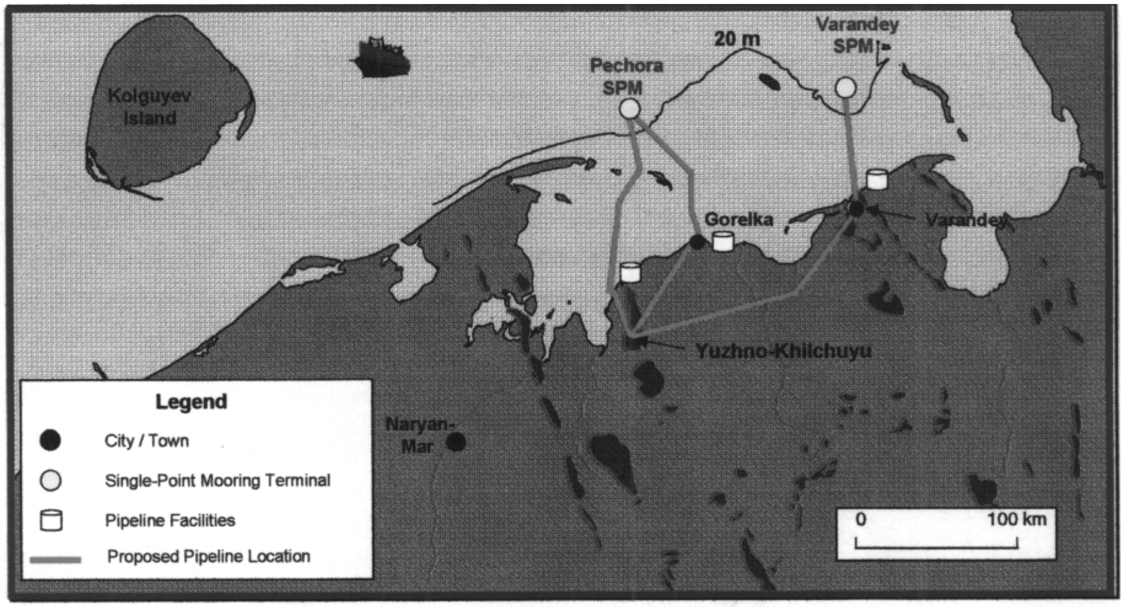

Figure 4. *Proposed offshore oil terminals.*

Paleozoic marine transgressions were related to expansion of the Ural seaway to the east, whereas Mesozoic transgressions originated in the Barents Sea to the north (Ressetar et al, 1997).

Structural Development

The structural development of the Timan-Pechora Basin is directly controlled by major plate boundary dynamics (Ziegler, 1998, 1989). Since the formation of the Ural Mountains in Permian time, the Timan-Pechora Basin has been in a foreland basin setting. Prior to the Permian, the basin setting has varied from an accretionary margin (Cambrian), a rift margin (Ordovician), a passive margin (Silurian) and a back-arc basin (Devonian and Early Carboniferous). The major tectonic events responsible for the present-day structural configuration of the Timan-Pechora Basin are shown in Figure 5.

As portrayed on the tectonic features map (Figure 2), the basin is made up of a series of north-northwest (NNW)-trending highs (referred to as ridges or swells) that bound intervening lows (troughs or depressions). The NNW-structural grain is a by-product not only of the effects of the foreland basin deformation associated with the suturing of the Ural Mountains during Permian time, but older tectonic events as well. A NNW-structural grain was developed in the basement rocks in the Cambrian as a result of the Balkalian Orogeny. Periods of extension and compression in the Ordovician and Devonian resulted in structures with similar NNW trends. Subsequent compressive events in the Carboniferous, Permian and Late Tertiary reactivated NNW-trending structures. Thus, the present day structural grain has been active in periods of compression and extension throughout the Phanerozoic.

Two periods of tectonic activity, the Devonian to Early Carboniferous (Visean) and the Permian, have left by far the largest impact on the area. Pulses of back-arc compression and extension resulted in a complex package of thick Devonian to Carboniferous Visean rocks that have multiple unconformities (Figures 6 and 7), (Rappoport, 1997; Schmidt, 1996; Ziegler, 1988). The back-arc basin formed in association with the

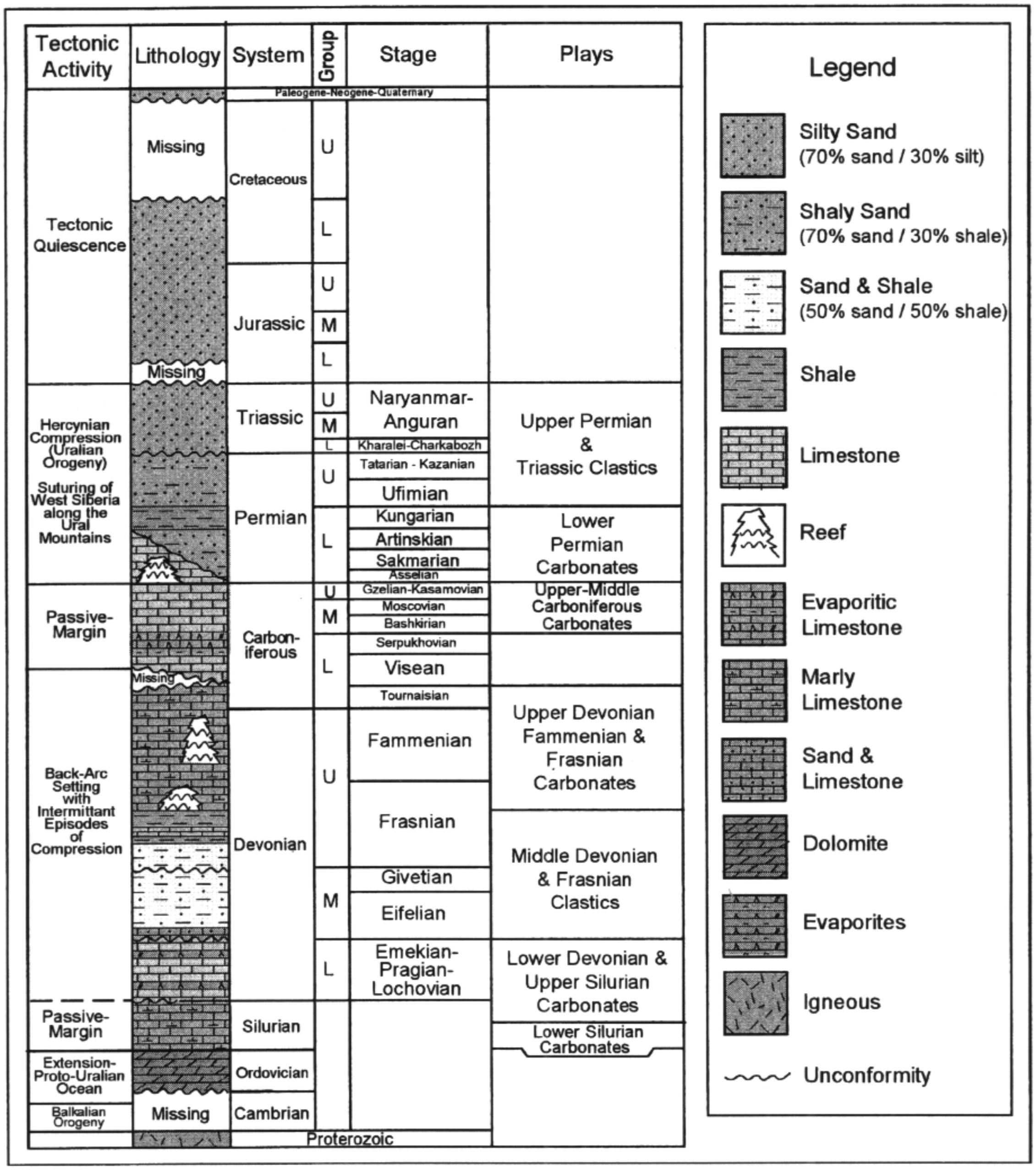

Figure 5. *Timan-Pechora generalized stratigraphy, tectonic activity and plays.*

'Sakmarian' arc-trench system that laid to the east of the Timan-Pechora Basin (Ziegler, 1988, 1989). Permian inversion associated with the Uralian Orogeny is responsible for the present day system of ridges and troughs.

The Khoreyver Depression and Kolva Swell characterize how the structural setting varies within the Timan-Pechora Basin. The Khoreyver Depression has undergone very little faulting or folding throughout the Phanerozoic (Figure 7). The Kolva Swell, lying to the west of the Khoreyver Depression, has been tectonically active throughout this same period. The Kolva Swell was one of two main rifts developed in the basin during Devonian time, namely the Kolva Rift. The other was the Pechora Rift, which coincides with the

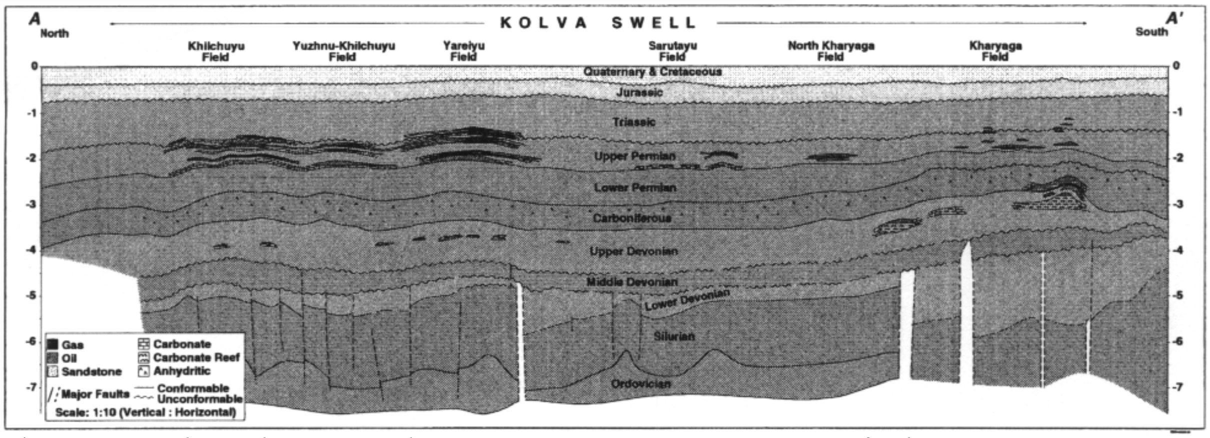

Figure 6. *North-south stratigraphic cross-section A-A'. See Figure 2 for location.*

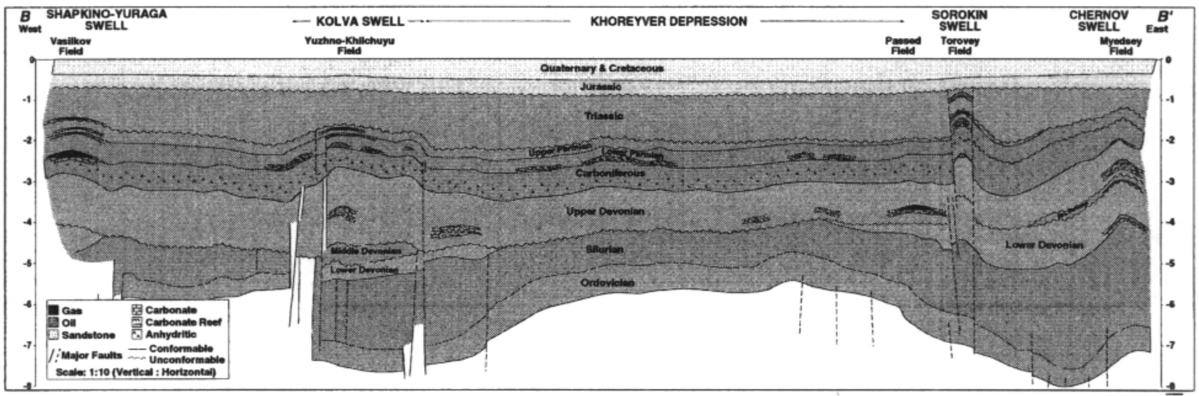

Figure 7. *West-east stratigraphic cross-section B-B'. See figure 2 for location.*

present day Timan Ridge (Figure 2). Evidence of tectonic activity in the Kolva Rift includes thick pods of Devonian sediments along with multiple events of folding and faulting (Figure 7). Significant inversion of the Kolva Rift took place during the Permian resulting in the present day structural high associated with the Kolva Swell (Figure 7).

The sedimentation history along the Kolva Swell reflects the tectonic history. During the Lower Permian, compression caused thinning of the Lower Permian section overlying the ridge (Figure 7). This is a fundamental change from the sedimentation pattern of Carboniferous-age and older rocks, where the Kolva Swell acted as a depo-center. The change in depo-centers was accompanied with a change in rock type; older carbonate rocks of Late Carboniferous age were replaced by siliciclastic rocks shed from the emerging Ural Mountains progressing from east to west.

Based on regional seismic data in the northern portion of the Timan Pechora Basin (Schmidt, 1996), the main phase of inversion that resulted in the NNW-trending swells, troughs and depressions occurred mainly during the Lower Permian (Asselian through Kungarian Stages). Inversion of the Kolva Swell began in the Upper Carboniferous indicated by partial thinning of the Carboniferous section onto the Kolva Swell as seen in Figure 7. Upper Permian sediments thicken only slightly off the flanks of the Kolva Swell. By the end of Triassic time, it appears the structural movement had entirely ceased as verified by the low relief exhibited on the top Triassic surface over the Kolva Swell.

Source Rock	Principle Kerogen Type	TOC Range (%)	TOC Average (%)	Gross Thickness Range (meters)	Main Region of Deposition
Middle – Upper Ordovician, Silurian and Lower Devonian	Type II	1 – 5	2	20 – 60	Khoreyver Depression, Kolva Swell, Middle – Pechora Swell, Varandey-Adzva Structural Zone,
Middle Devonian – Lower Frasnian	Type II (east) – Type III (west)	1 – 5	2	30 – 60	Kolva Swell, Middle - Pechora Swell, Pechora – Kolva Swell
Upper Devonian Lower – Middle Frasnian	Type II (?)	1 – 5	2	10 – 40	Pechora – Kolva Swell
Middle Frasnian (Domanik) – Carboniferous Tournaisian	Type II (east) – Type III (west)	2 – 10	3	20 – 240	Eastern half of basin including the East Timan Swell and Omra – Luza Saddle in the southwest
Lower Permian	Type III	1 - 5	2	50 – 100	Kolva, Shapkino-Yuraga and Sorokin Swells, Upper Pechora Trough

Table 1. *Timan-Pechora Basin source rock characteristics.*

Source Rocks

Five main source rock intervals exist in the Timan-Pechora Basin (Danilevsky, 1996). The intervals are as follows:

1. Middle - Upper Ordovician, Silurian and Lower Devonian
2. Middle Devonian - Lower Frasnian
3. Upper Devonian Lower - Middle Frasnian
4. Middle Frasnian (Domanik) - Carboniferous Tournaisian
5. Lower Permian

Table 1 summarizes key characteristics of each source rock interval where the present-day total organic carbon (TOC) is identified as greater than 1%. Source rocks having less than 1% TOC are considered to have marginal productivity (Danilevsky, 1996).

As a means to understand the relationship between petroleum system elements, field-size and hydrocarbon distributions, Wavrek et al (1997) utilized time-slice analysis to explain the observation by Ulmishek (1982) that a very limited number of fields account for 80 percent of in-place reserves. The analysis suggests that the most significant aspect of giant hydrocarbon accumulations is their early structural formation. Once structures were formed, the giant fields received multiple source rock hydrocarbon charges in response to basin fill and source rock expulsion. As an example, the Usa, Vozey and Kharyaga fields, located on the prolific Kolva Swell, contain approximately 3.5 Bbo total field reserves within four plays. Assuming a 30% recovery factor, in-place reserves are estimated at 11.7 Bbo.

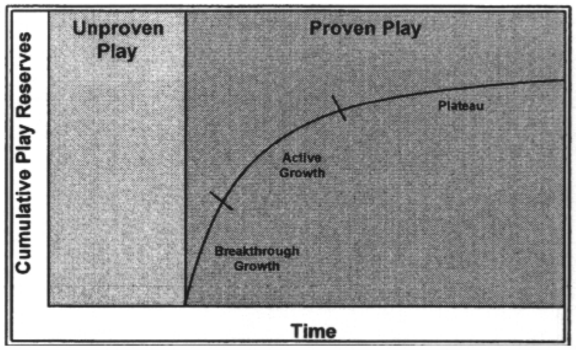

Figure 8. *Play classification system.*

Migration Pathways

The characterization of hydrocarbon migration pathways is important in understanding the petroleum system framework in the Timan-Pechora Basin. Michael and Fossum (1998) modeled regional cross-sections in the northern Nenets Okrug region to understand migration pathways and trap timing. Modeling was done to determine time of hydrocarbon generation and expulsion relative to trap development and the reason for hydrocarbon emplacement in Upper and Middle Carboniferous, Upper and Lower Permian and Triassic reservoirs. Modeling focused in the Kolva Swell and Khoreyver Depression areas.

Results of the 2D modeling indicated that vertical fault migration is required to explain hydrocarbon distributions in the north Timan-Pechora basin. The vertical extent of faults controls the degree of charge in Upper Carboniferous and Permian reservoirs. The modeling explains the major distribution of oil and gas in several areas of the Northern Timan-Pechora basin and emphasizes the critical effect that migration pathways and geopressure history have in determining the distribution of hydrocarbons.

PLAY ANALYSIS AND FUTURE OIL POTENTIAL - ONSHORE NENETS OKRUG AND KOMI REPUBLIC

Summary

Onshore, the exploration potential for discovering large fields in the Timan-Pechora Basin is low to moderate, and varies based on the geographic location and play. However the exploration potential of discovering large reserves in numerous small accumulations is high. Borovinskikh (1998) suggests that 700 hydrocarbon fields will be discovered in the Komi Republic, but that most of the fields will hold less than 75 Mmboe in place. It is thought that the discovery of many of these fields will be due to the continuing application of new technologies such as 3D seismic and integrated multi-discipline studies.

Figure 8 illustrates breakthrough, active growth and plateau phases, pertaining to discovery history and play classification in a basin. Eight of the nine identified plays, discussed below, have been characterized in the plateau phase. The potential of discovering large fields within the plateau phase plays is in general low. The remaining play is in the breakthrough phase, and the potential for discovering large fields is thought to be low to moderate.

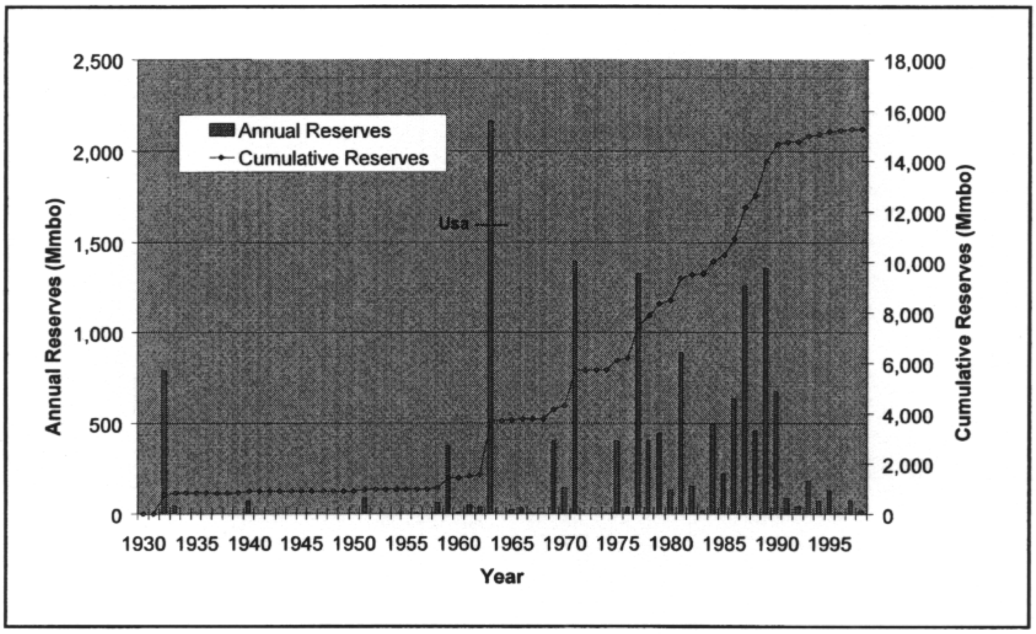

Figure 9. *Timan-Pechora creaming curve for oil discoveries. Usa, the largest oil field in the Timan-Pechora Basin is annotated.*

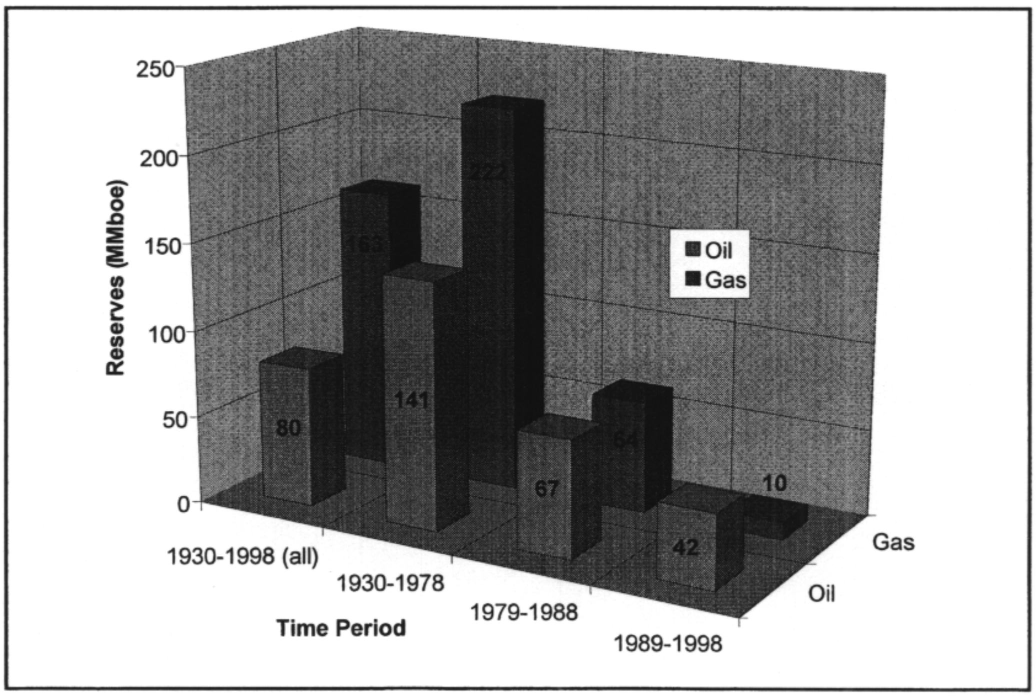

Figure 10. *Total oil and gas mean field-size versus time.*

Creaming curve and play analysis indicates that approximately 16 Bbo reserves have been discovered in the basin. Play analysis indicates that future added reserves will be in small to moderate increments, as the basin is in the plateau phase (Figure 9). However, possible reserves additions could be as great as 1 Bbo in the next ten years (Fossum, 1997). Borovinskikh (1998) calculates that potential total oil reserves in the Timan-Pechora Basin is 31.8 Bbo, suggesting that 15.8 Bbo reserves remain but in small accumulations. Figure 10 illustrates the decreasing mean discovered field size since hydrocarbons were first discovered in the 1930s.

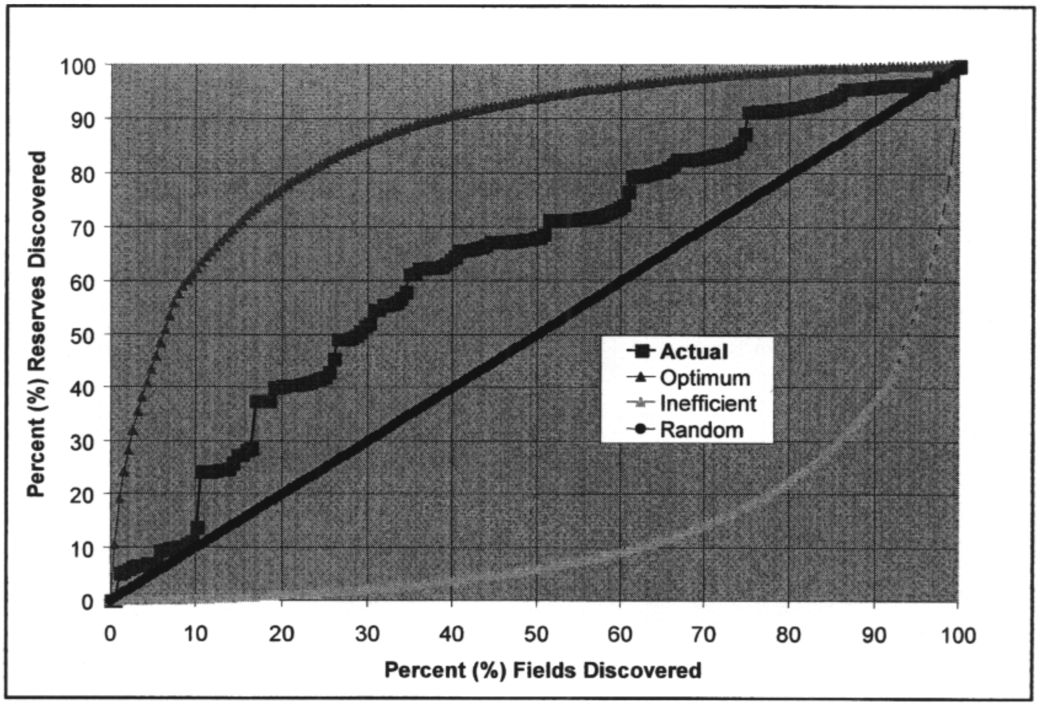

Figure 11. *Timan-Pechora exploration efficiency for oil discoveries.*

Numerous wells have thoroughly tested the main play concepts and prospects. Approximately 5,800 exploration (wildcat, step-out and reservoir evaluation) wells have been drilled in the Timan-Pechora Basin. The basin was explored, in general, from south to north and west to east in response to the exploration expeditions mentioned above, which thoroughly evaluated all main exploration targets in the onshore portion of the basin. The exploration strategy implemented in the Timan-Pechora Basin resulted in high exploration efficiency, demonstrated in Figure 11. The 'inefficient' curve describes a field discovery order if the smallest field was discovered first, then the next largest and so on. The 'efficient' curve describes a field discovery order if the largest field was discovered first, then the next smallest and so on. The 'random' curve is an average of the 'inefficient' and 'efficient' field discovery orders.

Summarizing, the exploration potential in the onshore portion of the basin has the following characteristics:

1. Limited prospect and reserves size due to mature plays.
2. Although numerous prospects exist, many are deep (greater than 4000 meters) and are situated off play fairways.
3. Plays may have a high-risk stratigraphic trap component, which leads to seal uncertainties.

The oil field development potential of the onshore Timan-Pechora Basin is substantial. Nearly 100 percent of the discovered reserves remain unproduced in the Nenets Autonomous Okrug and 60 percent of the discovered reserves are unproduced in the Komi Republic. Overall, 80 percent or 13 Bbo of the discovered reserves onshore remain unproduced. Figure 12 depicts annual oil and gas production since 1940, when the first oil production was recorded in the Yarega Field, Komi Republic. Note the severe drop and subsequent increase of production in the early-1990s, related to a loss of operating capital during Perestroika. The subsequent production increase in 1993 through present day was due to a slow influx of investments, both Russian and foreign, which focused on increasing production and bringing previously discovered fields on stream. One

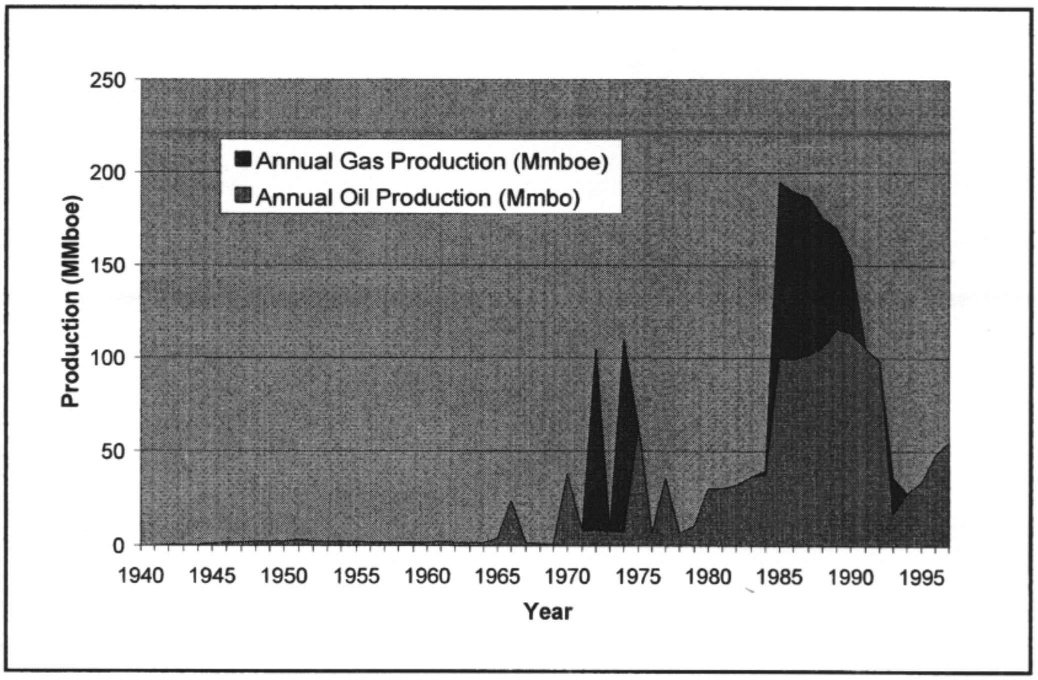

Figure 12. *Timan-Pechora annual oil and gas production. Cumulative production is 1.4 Bbo + 4.0 Tcfg.*

example is the Ardalin field, which started producing in 1994. Cumulative production through 1997 is 1.4 Bbo and 4.0 Tcfg (Fossum, 1997).

Schematic representations of the nine identified plays are depicted in Figures 16 through 21. Figure 15 illustrates the location of each schematic cross-section. Field-size distribution data statistics (oil only) for each play are listed at the bottom of each figure. The plays from oldest to youngest are:
1. Lower Silurian carbonates (Figure 16).
2. Upper Silurian and Lower Devonian carbonates (Figure 17).
3. Middle Devonian and Frasnian clastics (Figure 18).
4. Upper Devonian Frasnian carbonates (Figure 19).
5. Upper Devonian Fammenian carbonates (Figure 19).
6. Upper - Middle Carboniferous carbonates (Figure 20).
7. Lower Permian carbonates - structural (Figure 20).
8. Lower Permian carbonates - stratigraphic (Figure 20).
9. Upper Permian and Triassic clastics (Figure 21).

A summary of each play follows (Fossum, 1997). The Ordovician carbonates play is not discussed here due to the relatively small amount of hydrocarbons discovered in the interval. The only known Ordovician discovery is in the Srednyaya Makarikha field, located in the Khoreyver Depression (Figure 2). Additional undocumented Ordovician hydrocarbon accumulations may exist but are considered insignificant. However, in the interest of completeness, Ordovician field-size statistics have been included in the reserves summary figures (Figures 9 through 11 and Figures 12 and 13).

Cumulative discovered reserves and mean field-size versus time have been depicted in Figures 13 and 14 for five plays. Due to data limitations, three of the five plays, Ordovician, Silurian and Lower Devonian carbonates, Upper Devonian carbonates and Upper / Middle Carboniferous and Lower Permian carbonates depicted in Figures 13 and 14, represent compilations of the cumulative oil reserves discovery history and mean oil field-size versus time respectively (Fossum, 1997).

Lower Silurian Carbonates Play

This play has moderate to high exploration risk, is in plateau phase (Figure 13) and has small potential exploration reserves. Figure 14 illustrates the decreasing mean field-size throughout time within the compiled Ordovician, Silurian and Lower Devonian carbonates play discovery history curve.

The Lower Silurian play is comprised of vuggy, algal dolomites of the Sandivey and Veyak Formations. The play is proven in the south Khoreyver Depression area on the flank of the Sandivey High (Figures 2 and 16). Vertical seal is provided by Upper Devonian Frasnian argillaceous shales and side seal by a pinchout onto the structural high and a series of reverse faults to the southwest (reverse faults not illustrated in Figure 16).

Analogous fields to the south and on trend have a Lower Silurian reserves range of 5 to 135 Mmbo. The critical uncertainty for this play is reservoir quality. Predicted porosity is poor to fair and difficult to predict. Porosity development is patchy due to dolomitization of limestone related to subaerial exposure surfaces. Hydrocarbon charge is provided by Ordovician and Silurian Type II marine source rocks (Danilevsky, 1996).

Upper Silurian and Lower Devonian Carbonates Play

This play has moderate to high exploration risk, is in plateau phase (Figure 13) and has small to moderate potential exploration reserves. Figure 14 illustrates the decreasing mean field-size throughout time within the compiled Ordovician, Silurian and Lower Devonian carbonate plays.

The play is proved in two regions, the eastern Khoreyver Depression and the Varandey-Adzva Structural Zone (Figure 2). The Roman Trebs, A. Titov and Kolva fields, located in the eastern Khoreyver Depression, are comprised of vuggy, dolomitic Lower Devonian limestones, which were eroded and sealed by Upper Devonian Frasnian argillaceous carbonates. A total of thirteen fields are situated within the Varandey-Adzva Structural Zone and are comprised of hydrocarbons in Upper Silurian and Lower Devonian vuggy dolomites sealed by marls of the same age (Figure 17). Hydrocarbon charge is provided by Ordovician and Silurian Type II marine source rocks (Danilevsky, 1996). Hydrocarbon quality within the Upper Silurian and Lower Devonian is a concern, as the oil reserves tend to be high in paraffin, resins and asphaltines (Aminov et al, 1993, Lodzhevskaya and Smolenchuk, 1998).

Middle Devonian and Frasnian Clastics Play

This play has moderate to high exploration risk, is in plateau phase (Figure 13) and has small to moderate potential exploration reserves.

Sediments of the play are comprised of the Middle Devonian Givetian and Eifelian clastics units and the Upper Devonian Frasnian clastics unit. The principal depositional environment is foreshore lower beach and shallow marine shoals and the principal lithology is sandstone, with clay and lag deposits noted. Reservoir quality is poor to good, controlled in part by porosity reduction due to compaction effects. The play predominates in the Kolva Swell, particularly in the Usa and Vozey fields (Usa and Vozey are the two largest onshore fields in the play) and the Kharyaga field. See Figure 19 for EUR reserves within the play. Porosities generally range from 8% to 11% and permeabilities from 90 to 120 millidarcies in the Kolva Swell region in lower beach and shallow-marine shoal facies. Permeabilities are as high as 900 millidarcies in the Kharyaga field in the shallow marine facies (Nikonov and Bogatsky, 1996).

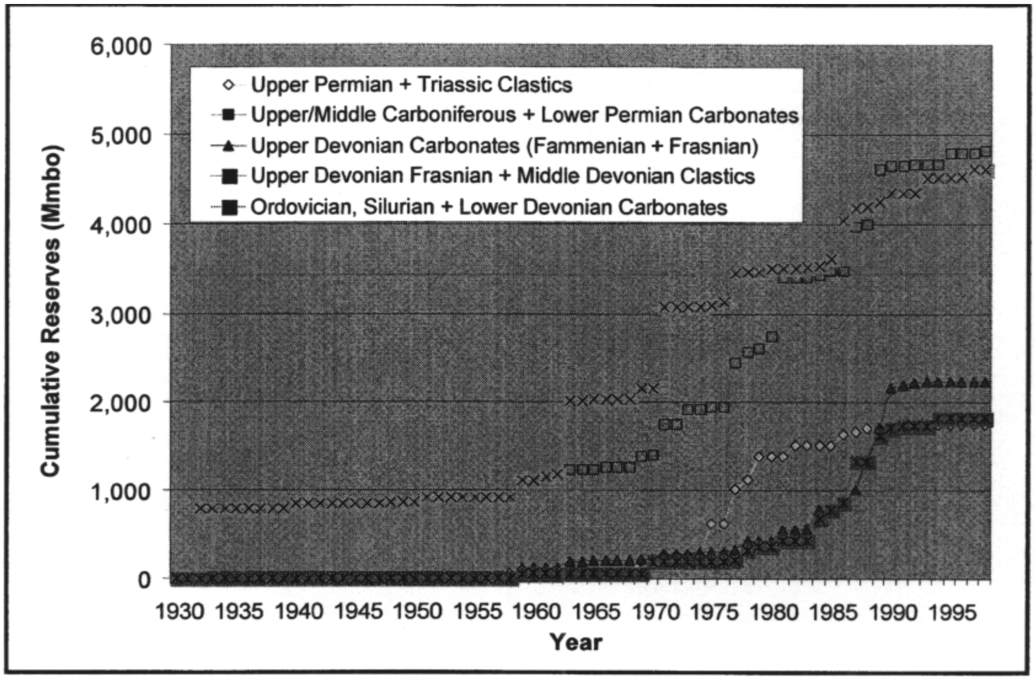

Figure 13. *Cumulative discovered oil reserves by play. Due to data limitations, the Ordovician, Silurian and Lower Devonian carbonates, Upper Devonian carbonates and Upper/Middle Carboniferous carbonates plays represent compiled cumulative field discovery distributions.*

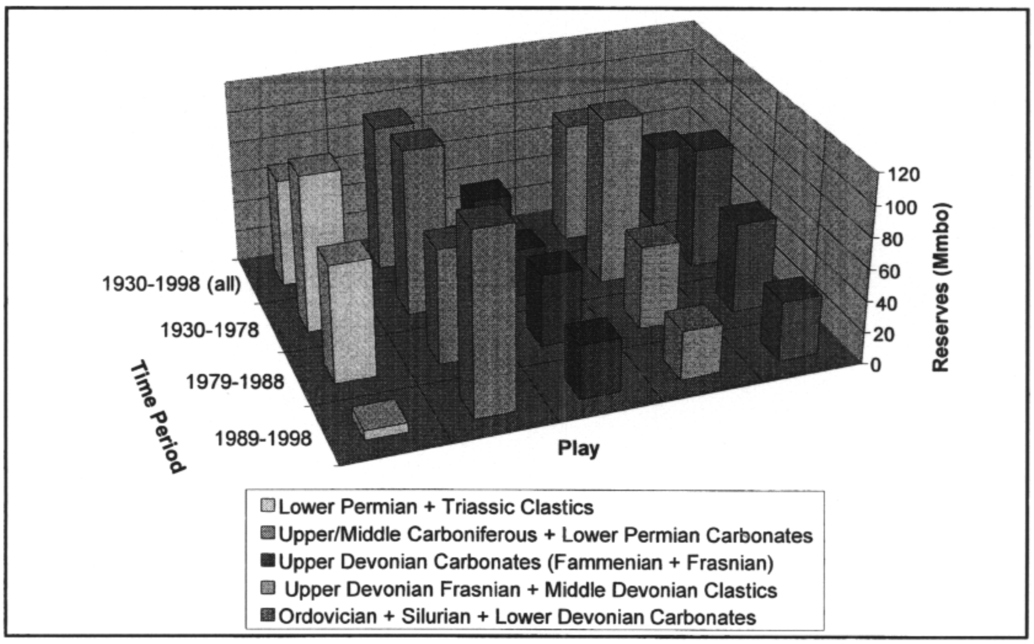

Figure 14. *Mean oil field-size versus time by play. Due to data limitations, the Ordovician, Silurian and Lower Devonian carbonates, Upper Devonian carbonates and Upper/Middle Carboniferous carbonates plays represent compiled field-size distributions.*

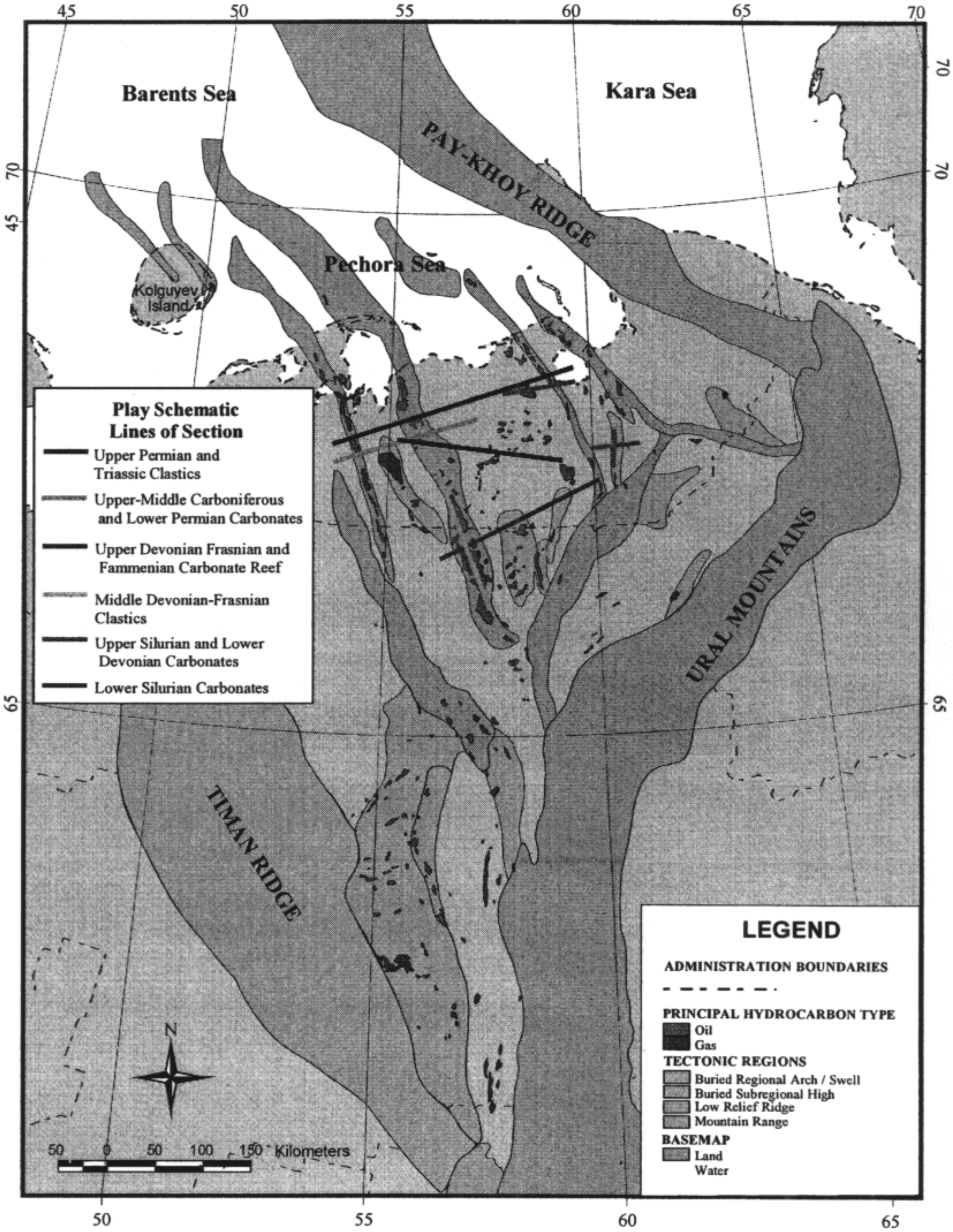

Figure 15. *Index map for schematic cross-section lines-of-section.*

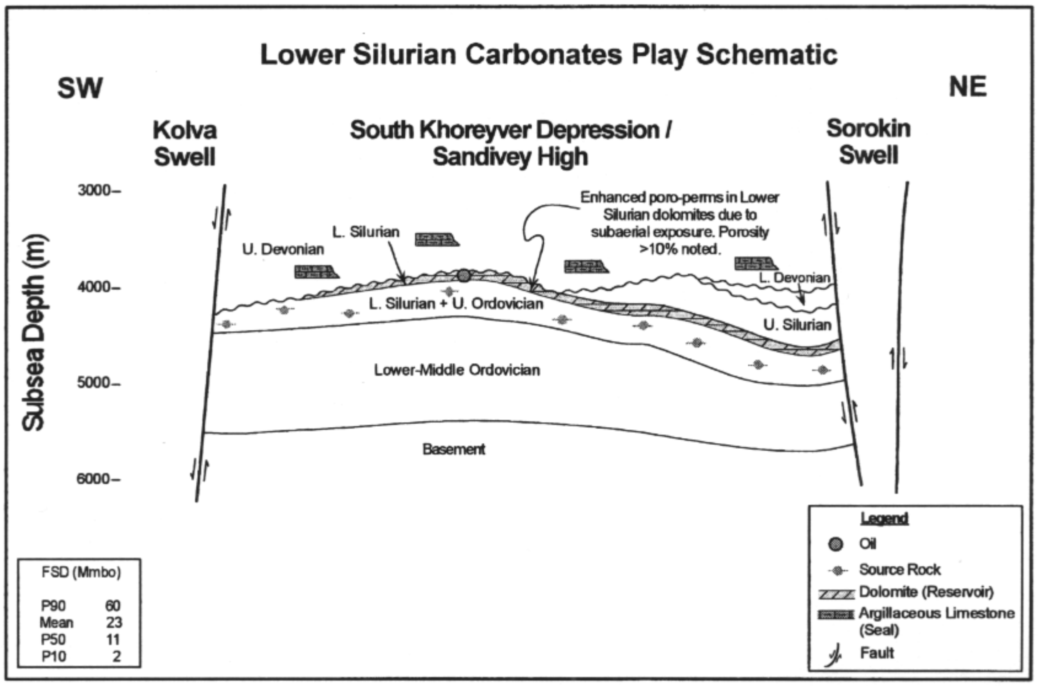

Figure 16. *Lower Silurian carbonates play schematic. See Figure 15 for line-of-section.*

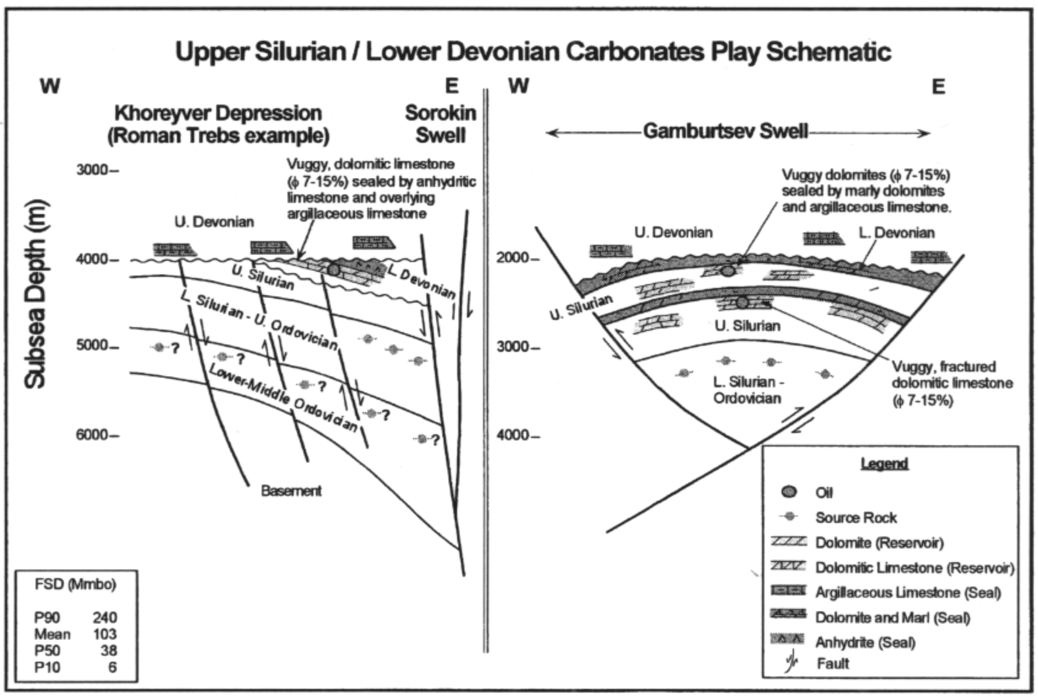

Figure 17. *Upper Silurian and Lower Devonian carbonates play schematic. See Figure 15 for line-of-section.*

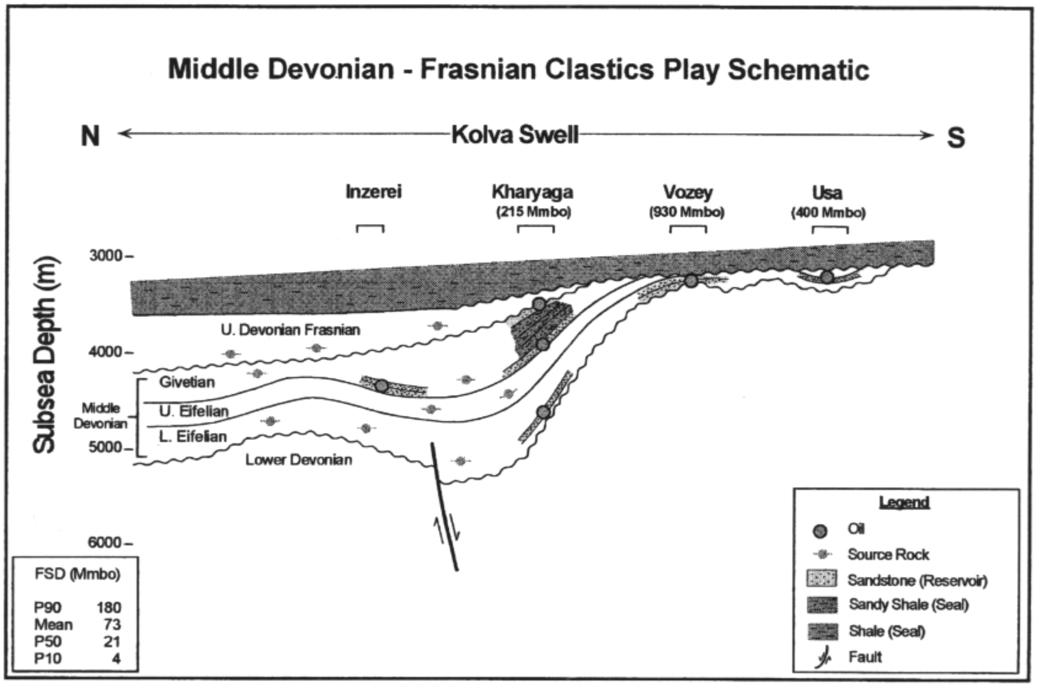

Figure 18. *Middle Devonian and Frasnian clastics play schematic. See Figure 15 for line-of-section.*

Principal trap type is combination, and encasing shales provides side and top seal (Figure 18). The critical uncertainty is reservoir quality. This play is most likely sourced from Ordovician - Silurian - Lower Devonian Type II source rocks and Middle Devonian Type II source rocks (Danilevsky, 1996).

Upper Devonian Frasnian Carbonates Play

The Upper Devonian Frasnian carbonate reef play has high exploration risk, is in plateau phase (Figure 13) and has small potential exploration reserves. The Frasnian carbonate play is comprised of two sub-plays, the Domanik and Sirachoy - Ukhtinsky Formation reef trends (Figure 19).

The Frasnian Domanik inner shelf reef trends generally north - south through the Nenets Okrug and Komi Republic region. The principal lithology is a vuggy, coralline dolomite with minor anhydrite. Porosity ranges from 7 to 15 percent (Nikonov and Bogatsky, 1996). Principal trap type is stratigraphic. Side seal is provided by the regionally significant, actively generating middle-shelf Domanik source rock facies to the east and the tight, marly inner shelf Domanik carbonates to the west (Figure 19). The Domanik Type II source rock on the east, which is very prolific, is an organic rich middle - shelf limestone with interbedded marls, argillites and chert. The Domanik facies extends from the Pechora Sea to the southern extent of the Timan-Pechora Basin and into the Volga - Ural Basin. The Domanik is within the present-day oil window in a large portion of the basin and is generally oil prone east of the reef trend and gas prone to the west (Danilevsky, 1996). Top seal is an uncertainty as it may be compromised of the potentially overlying Upper Devonian Frasnian Sirachoy - Ukhtinsky reef trend (Figure 19). However, the Upper Devonian Domanik reef play is proven to the north in the Roman Trebs Field. The principal critical uncertainty for this sub - play is reservoir quality. The principal lithology is dolomite.

Porosity in the Frasnian Sirachoy - Ukhtinsky reef unit is poor to fair and the principal trap type is

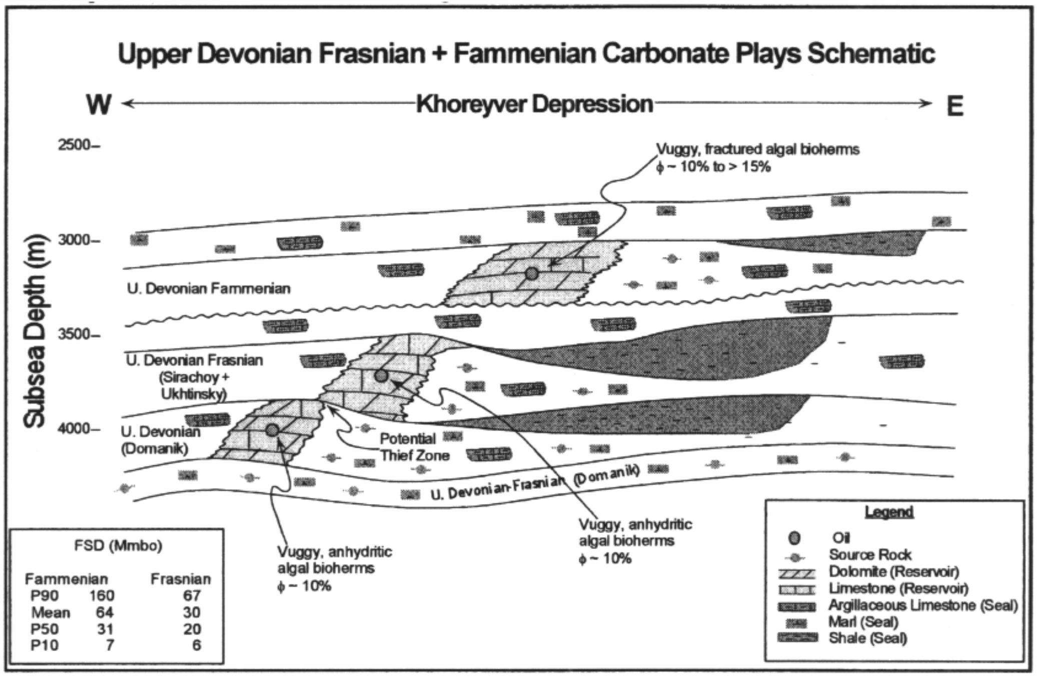

Figure 19. *Upper Devonian Frasnian and Fammenian carbonates play schematic. See Figure 15 for line-of-section.*

stratigraphic. The regionally significant, actively generating middle-shelf Frasnian Domanik source rock to the east and the tight, inner-shelf Frasnian carbonates to the west provide side seal. Top seal is provided by the overlying basal tight Upper Devonian Fammenian carbonates (Figure 19) and hydrocarbon charge by the prolific Upper Devonian Type II Domanik source rock (Danilevsky, 1996). The critical uncertainty for this sub-play is reservoir quality.

Upper Devonian Fammenian Carbonates Play

The Upper Devonian Fammenian carbonate reef play is prolific. The reef play has low to moderate exploration risk, is in plateau phase (Figure 13) and has moderate potential exploration reserves. The mean field-size has remained somewhat constant throughout the play development (Figure 14), presumably due to the ubiquitous similar size of the reef features.

Upper Devonian Fammenian reef carbonates have been producing in the Ardalin field within the Khoreyver Depression Polar Lights block since 1996. The Ardalin Field is situated above the Arctic Circle, which makes it the northern-most continuously producing field in the Timan-Pechora Basin. Produced oil from the Ardalin field is transported to the south, through the Kharyaga - Usinsk - Ukhta pipeline system. Current production is 40,000 bopd.

Fammenian reef carbonates are comprised of vuggy, fractured algal bioherms (Figure 19). Hydrocarbons within the play are sealed by Upper Devonian argillaceous carbonates and charged by Upper Devonian Domanik Type II source rocks (Danilevsky, 1996) and in some instances by Silurian Type II source rocks (Wavrek, 1997). Fammenian and Frasnian reefs tend to form on paleo-highs, particularly the Bolshezemelsky basement high (Bogatsky et al, 1996 and Rappoport, 1997).

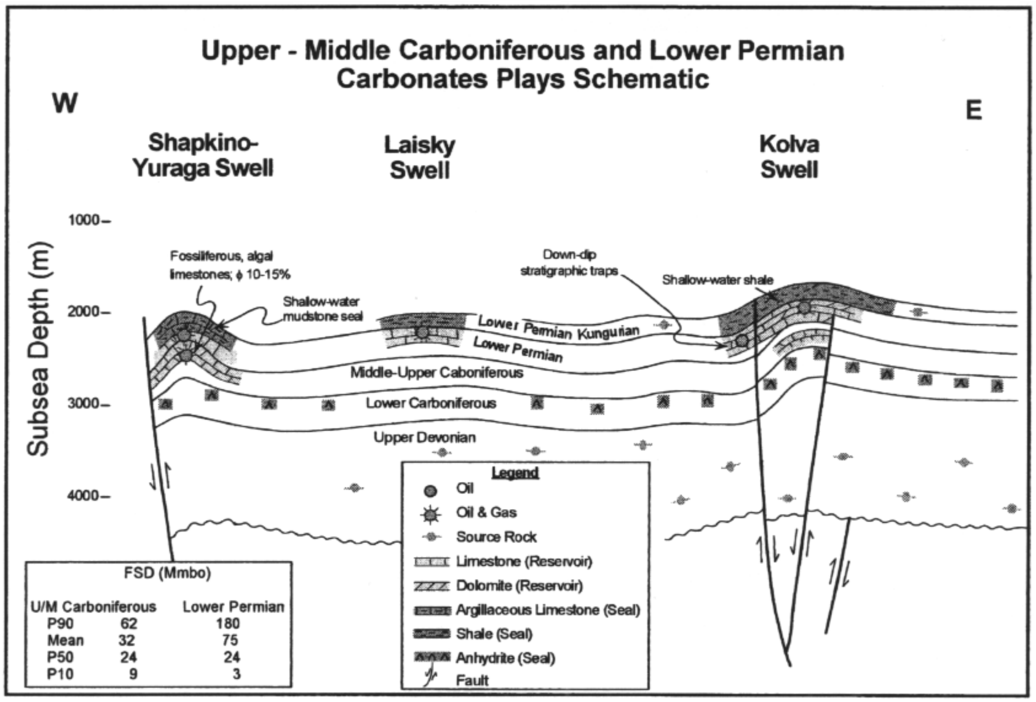

Figure 20. *Upper-Middle Carboniferous and Lower Permian carbonates play schematic. See Figure 15 for line-of-section.*

Upper-Middle Carboniferous Carbonates Play

The Upper-Middle Carboniferous exploration play is comprised of fossiliferous, algal limestones sealed by interbedded argillaceous limestones of the same age. The trap type is primarily structural, however, downdip stratigraphic traps exist (Figure 20).

The unit holds primarily gas and gas-condensate to the west in the Shapkino-Yuraga Swell, charged from Middle Devonian Type III terrigenous gas-prone source rock facies predominant in the northwest portion of the basin (Danilevsky, 1996). The Upper - Middle Carboniferous carbonate unit is oil-prone in the southern Kolva Swell and Sandivey High, where the hydrocarbon charge is from the marine Upper Devonian Domanik Type II source rock and possibly the Ordovician Type II source rock (Wavrek et al, 1997).

The Upper-Middle Carboniferous play has moderate exploration risk, is in plateau phase (Figure 13) and has small potential exploration reserves.

Lower Permian Carbonates Play - Structural and Stratigraphic

The Lower Permian exploration play is comprised of two components - stratigraphic and structural (Figure 20). The structural play is situated mainly on the Kolva Swell and has been extensively drilled. The play has moderate risk, is in plateau phase (Figure 13) and has small to moderate potential exploration reserves. Figure 14 illustrates that the mean field size for this play increased in the last ten years, due to an extension of the play into the Pechora Sea with the discovery of Prirazlomnoye (EUR 609 Mmbo). In a comparison, the mean field size for the other eight plays either decreased or remained the same.

The primary reservoir unit within the Lower Permian carbonate play is the Asselian - Sakmarian (Figure 5). The unit is predominantly a barrier - type reef composed of bioherm structures and detrital limestone. Principal lithology is dolomitic limestone, and dolomite and anhydrite are common. Porosity development is mainly secondary due to subaerial exposure and freshwater dissolution. The principal trap type is structural with a downdip stratigraphic component. The regionally extensive Lower Permian Kungarian and Artinskian marine shale provides top and side seal. Hydrocarbon charge is provided primarily by the Upper Devonian Type II Domanik source rocks (Danilevsky, 1996 and Wavrek et al, 1997). Critical uncertainties for the Lower Permian carbonate play include reservoir quantity and quality.

The Lower Permian carbonates stratigraphic play, which is a follow-up to the more prolific structural play, has moderate risk, is in breakthrough phase and has small to moderate potential exploration reserves. The stratigraphic play focuses on the downdip potential of Lower Permian structural features, defined primarily through the application of 3D seismic data. In 1996, a successful well was drilled on the south flank of the Yuzhno-Khilchuyu field. The well was drilled to establish the occurrence of hydrocarbons below the main oil-water contact in the field.

The downdip stratigraphic play type concept may be applied to other Lower Permian carbonate fields within the play fairway, and to other carbonate reef or bioherm reservoirs in the Timan-Pechora Basin, provided adequate data is acquired to identify the potential.

Upper Permian and Triassic Clastics Play

The Upper Permian and Triassic clastics play reservoir facies is laterally extensive throughout the Timan-Pechora Basin, but the play fairway tends to overlay the present-day positive structural features (Figure 21). The depositional environment ranges from deltaic in the Upper Permian to fluvial and lacustrine in the Early Triassic. Sands are generally of excellent quality (porosity > 20%), but tend to be mostly thin and discontinuous, except in localized areas (Nikonov and Bogatsky, 1996). As with the Upper - Middle Carboniferous carbonates play, hydrocarbon occurrence tends to be gas and condensate prone to the west in the Shapkino-Yuraga and Kolva Swells and oil prone to the east in the Varandey-Adzva Structural Zone. This is due to variations in the source rock organic facies (Danilevsky, 1996, and Wavrek et al, 1997).

The Upper Permian and Triassic clastics play has moderate risk, is in plateau phase (Figure 13) and has small to moderate potential exploration reserves.

PLAY ANALYSIS AND FUTURE POTENTIAL - OFFSHORE PECHORA SEA, MURMANSK DISTRICT

Limited data is available for the Pechora Sea region and therefore a detailed level of analysis is not possible. However, exploration potential does exist, as the area is immature in terms of exploration history. Four main plays (Lower Devonian carbonates, Upper Devonian carbonate reefs, Lower Permian carbonates and Upper Permian and Triassic clastics), which are extensions of proven plays within the onshore portion of the basin, extend into the Pechora Sea and define the offshore exploration potential (see Figures 17, 19, 20 and 21 for play schematics). The offshore portions of the plays are in active growth and possibly breakthrough phases. Creaming curve analysis indicates that approximately 1 Bbo have been discovered to date (Figure 22) and that future added reserves will be in large increments. Total undiscovered reserves might be as high as 4 Bbo (Fossum, 1997). Nearly 100 percent of the discovered reserves remain unproduced. Critical uncertainties for Pechora Sea exploration include infrastructure, costly and hostile arctic drilling conditions (severe weather and

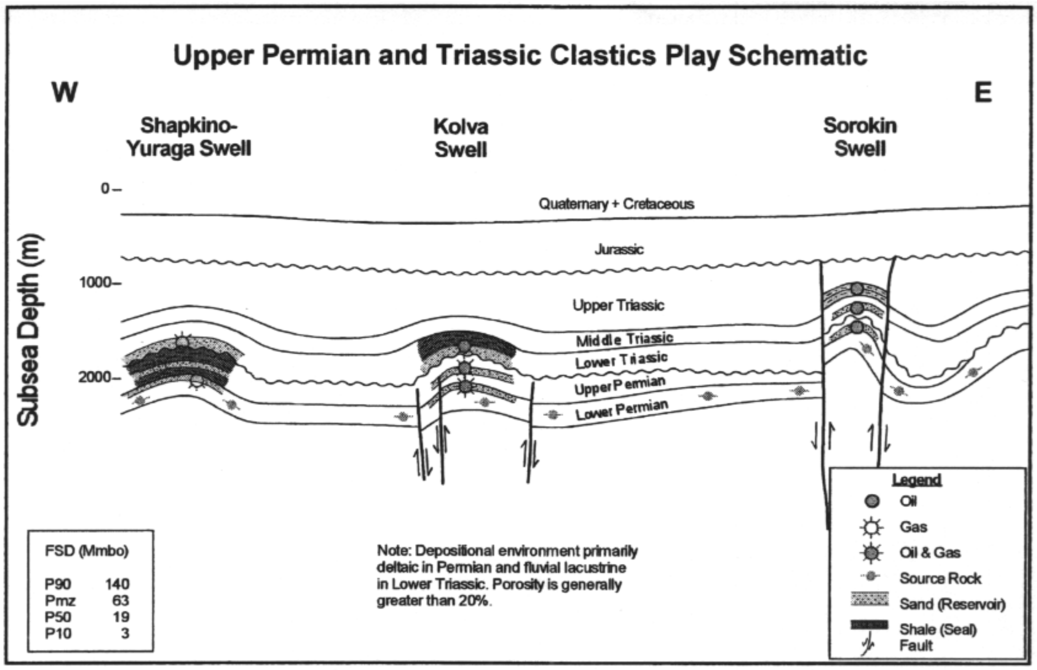

Figure 21. *Upper Permian and Triassic clastics play schematic. See Figure 15 for line-of-section.*

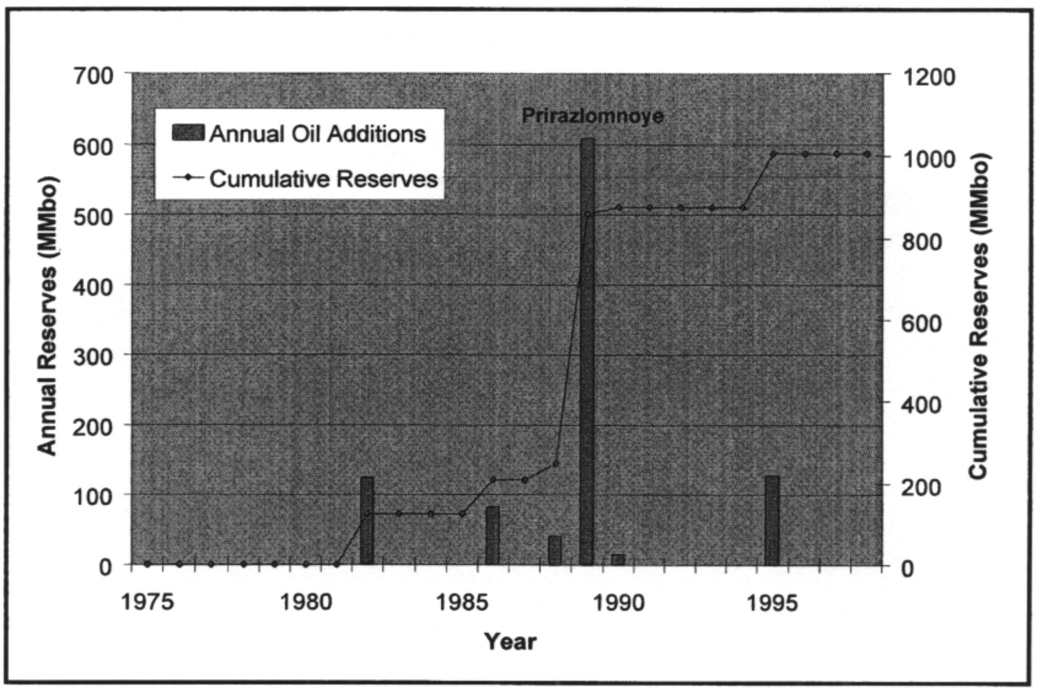

Figure 22. *Pechora Sea creaming curve, Prirazlomnoye, the largest oil field in the Pechora Sea is annotated.*

ice), political environment and high exploration costs.

CONCLUSIONS

Results indicate that nine proven exploration and development plays have been identified in the onshore portion of the Timan-Pechora Basin. Eight of the nine plays are characterized in the plateau phase, and one in breakthrough phase. The breakthrough phase was possible with the application of new technologies such as 3D seismic acquisition, processing and interpretation and the application of integration techniques, where multi-discipline teams were utilized to maximize the value of acquired data.

Extracting value from the Timan-Pechora Basin lies primarily in field development and secondarily in exploration. Both field development and exploration projects require proximity to existing infrastructure to enhance value. Three plays represent the largest portion of the field development potential: the Lower Permian carbonates - structural play, the Upper Devonian Fammenian carbonates play and the Lower Devonian carbonates play. The Upper Permian - Triassic clastics play has moderate field development potential. Overall, 80% or 13 Bbo of the discovered reserves onshore remain unproduced. Exploration potential in the Pechora Sea exists in the same four plays.

Detailed basin analysis has indicated that 1 Bbo onshore and 4 Bbo in the Pechora Sea may be discovered in the next ten years. The total future exploration potential of the basin may be as high as 15.8 Bbo. While this is a large number, the challenge for the industry, both foreign and Russian investors, is that the reserves will be in small accumulations (75 Mmboe or less) and in the harsh operating environment the ability to develop such small accumulations will be difficult.

ACKNOWLEDGEMENTS

The authors wish to thank the management from Conoco, Inc, OAO Arkhangelskgeoldobycha, the Timan-Pechora Scientific Research Center and the Environmental and Geoscience Institute (University of Utah) for permission to publish this paper. We also thank Dave Warwas, Jessie Aguilar and Debbie Hall for providing excellent drafting support.

REFERENCES CITED

Aminov, L. Z., M. Belonin, V. I. Bogatsky, A. P. Borovinskikh, V. Gaideek, Eu. Grunis, S. Danilevsky, V. Makarevich, Yu. Pankratov, O. Prischepa, Yu. Trifachov, and V. Kholodilov, 1993, Oil and Gas Potential and Economic and Geological Parameters of Preparation and Development of Hydrocarbons in the Timan-Pechora Province, VNIGRI report, 92 pp.

Barringer, J. J., 1998, Characterization of Regional Landforms and Landscape Analysis in Support of an Oil Field Development in the Remote Arctic Timan-Pechora Region of Russia, SPE 46753, AAPG Abstract.

Bogatsky, V. I., N. A. Bogdanov, S. L. Kostyuchenko, B. V. Senin, S. F. Sobolev, E. V. Shipilov, and V. E. Khain, 1996, Tectonic Map of the Barents Sea and the Northern Part of European Russia: Institute of the

Lithosphere, Russian Academy of Sciences, Moscow, Russia.
Borovinskikh, A. P., 1998, The Fuel and Energy Potential of Russia's European North Region. The Current State and Development Strategy, MRR, January 1998, pp. 14-31.
Danilevsky, S., 1996, Oil and Gas Generative Potential of the Oil and Gas Complexes within the Continental Portion of the Timan-Pechora Sedimentary Basin, Conoco commissioned report by Timan-Pechora Scientific Research Center, 13 pp.
Fossum, B. J., 1997, Timan-Pechora Basin Regional Phase II Evaluation, Conoco unpublished internal report.
Lodzhevskaya, M. I. and T. N. Smolenchuk, 1998, Fluid Dynamic Aspects of Oil Migration and Accumulation in the Northeast of the Timan-Pechora Basin, Petroleum Geoscience, Vol. 4, pp. 111-120.
Magoon, L. B. and W. G. Dow, 1994, The Petroleum System *in* The Petroleum System from Source to Trap: AAPG Memoir 60, p. 3-24.
Michael, G. E. and B. J. Fossum, 1998, Regional 2D Maturation Models, Northern Timan-Pechora Basin, Russia, AAPG poster session extended abstract.
Nikonov, N. and V. I. Bogatsky, 1996, Regional Tectonic and Lithologic Characteristics of the Timan-Pechora Sedimentary Basin, Conoco commissioned report by Timan-Pechora Scientific Research Center, 18 pp.
Rappoport, B. I., 1997, Regional Geological Studies to Evaluate Oil and Gas Prospects of the Northern Territory, Conoco commissioned report by OAO Arkhangelskgeoldobycha, 30 pp.
Ressetar, R., D. Hobday, (Energy and Geoscience Institute) and B. Pimenov, (Komi Science Center), 1997, Tectono-Stratigraphic Framework *in* Petroleum Systems of the Timan-Pechora Basin, Russia, Energy and Geoscience Center Technical Report No. 97-5-20940, v. 2a.
Schmidt, W. J., 1996, Tectonics and Structural History, Nenets Autonomous District, Timan Pechora Basin, Russia, Conoco unpublished internal report, 18 pp.
Ulmishek, G., 1982 Petroleum Geology and Resource Assessment of the Timan-Pechora Basin, USSR, and the Adjacent Barents-Northern Kara Shelf, U. S. Department of Energy Study, 195 pp.
Wavrek, D. A., D. K. Curtiss, R. Ressetar, and R. Erhlich, 1997, Petroleum Systems in Petroleum Systems of the Timan-Pechora Basin, Russia, Energy and Geoscience Institute Technical Report No. 97-5-20940, v. 1.
Ziegler, P. A., 1988, AAPG Memoir 43: Evolution of the Arctic-North Atlantic and the Western Tethys, 198 pp.
Ziegler, P. A., 1989, Evolution of Laurussia: A Study in Late Paleozoic Plate Tectonics, Kluwer Academic Publishers, 102 pp.