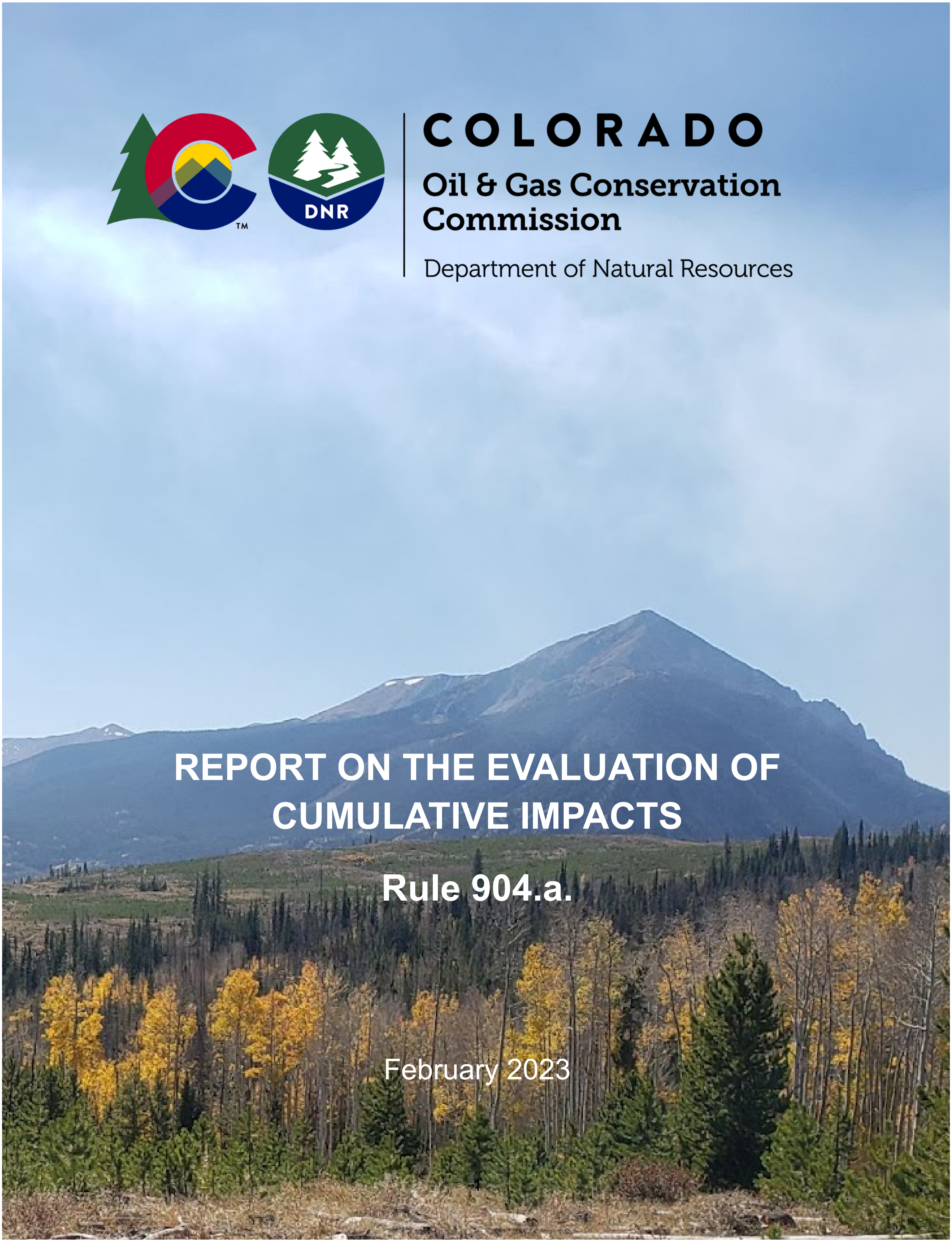


COLORADO

Oil & Gas Conservation Commission

Department of Natural Resources

REPORT ON THE EVALUATION OF CUMULATIVE IMPACTS

Rule 904.a.

February 2023

COLORADO
Oil & Gas Conservation Commission
Department of Natural Resources

1120 Lincoln Street, Suite 801
Denver, CO 80203

Commissioners,

It is with great satisfaction that I provide you with the second annual Report on the Evaluation of Cumulative Impacts. This report is intended to establish a baseline and inform the Commission of data, trends, and considerations in your ongoing evaluation and assessment of potential cumulative impacts consistent with SB 19-181.

During 2022, the Commission and Staff's work led to the approval of 47 Oil and Gas Development Plans (OGDPs). The addition of these OGDPs greatly expanded the Cumulative Impacts Data Evaluation Repository (CIDER) data set. In comparison, the data in last year's report was limited to the 7 OGDPs approved in 2021, and this increased data set allows for more robust and detailed analysis. In addition, with the second year of data, valuable insight from a review of year over year trends is, for the first time, possible. This allowed us to include numerous new, more comprehensive charts conveying information reflective of the additional data.

Also new in this year's report are some data or information requested by the Commission over the course of the last year. During the December 2022 hearing, the Commission shared many ideas for inclusion in this report, and those that Staff and I agreed were feasible and could reasonably be achieved within the timeline of the report are included.

Recognizing the growth between the first and second report, I acknowledge that there is plenty of room for continued growth. For example, comparisons of actual water use during drilling and completion and actual air emissions to their estimated values as provided in CIDER. The presentation and data contained in the cumulative impacts report will continue to evolve with each iteration as our data, assessment tools and knowledge continues to evolve. Similarly, CIDER data for future oil and gas locations related to one of the three Comprehensive Area Plans (CAP) that the Commission approved in 2022 will be collected as part of the OGDP process and, therefore, will be included in the annual reports for the years in which the OGDP is considered rather than this year's report.

Finally, concurrent to the preparation of this report, the Commission initiated a stakeholder outreach process on cumulative impacts under the leadership of Commissioner Ackerman. This process was initiated with a series of four meetings that sought input on the COGCC's approach to further address cumulative impacts. This year's report has been prepared independent of this process, and recognizes that the results of this stakeholder outreach process may inform the preparation of this report in the future. I eagerly anticipate feedback from this second report iterating future cumulative impact reports as well as integrating into the Commission's broader cumulative impacts stakeholder process.

Looking forward, Staff and I are committed to continuing to collect and evaluate data. We look forward to advancing our knowledge of cumulative impacts as we expand our dataset and continue to learn.

Sincerely,

Julie Murphy, Director

Table of Contents

Background

On April 16, 2019, Governor Polis signed Senate Bill 19-181 (SB19-181) into law. SB19-181 changed the Oil and Gas Conservation Act's (the "Act") legislative declaration to direct the Commission to "[r]egulate the development and production of the natural resources of oil and gas in the state of Colorado in a manner that protects public health, safety, and welfare, including protection of the environment and wildlife resources," C.R.S. § 34-60-102(1)(a)(I) (2020). Subsequently the Commission began a series of rulemakings to accomplish this and other specifics identified in SB19-181, including the statutory mandate to adopt rules, in consultation with the Colorado Department of Public Health and Environment ("CDPHE"), to "evaluate and address the potential cumulative impacts of oil and gas development." C.R.S. § 34-60-106(11)(c)(II). These rulemakings are referred to as the Mission Change Rulemakings. Part of the evaluation of cumulative impacts is met through the adoption of Rule 904: Evaluating Cumulative Impacts.

Primary to Rule 904 is an annual report to the Commission. The first annual report was delivered to the Commission on Jan. 18, 2022. The first report was intended to set the foundation, and begin to set the baseline, for subsequent annual reports. It also acknowledged that the first year's data set was limited, and the specific fields or ways to present data may need to evolve as Staff and/or Commissioner understanding of the data and/or the impacts evolves. In this second annual report, data were evaluated for Oil and Gas Development Plans (OGDPs) and associated Oil and Gas Locations (OGDP Locations) approved in the 2022 calendar year. This second report also includes numerous additional ways to look at information gathered into the Cumulative Impacts Data Evaluation Repository (CIDER), such as enhanced graphics to more accurately represent the expanding suite of data and year over year trends to understand how these impacts may be changing over time.

Three Comprehensive Area Plans (CAPs) were approved in 2022. These CAPs allow operators and COGCC to look at development plans on a broader scale, which invites discussions that may not otherwise occur (e.g. more robust infrastructure) that may inform cumulative impacts. While CAPs can be a valuable tool during the planning and approval process, the Form 2B (Cumulative Impacts Data Identification) for a specific location collects the relevant CIDER data. For consistency and in order to compare the locations in these CAPs to other OGDPs, the information for OGDP Locations included in these CAPs will be included in the year in which the OGDP is approved. The three operators whose CAPs were approved in 2022 agreed to provide cumulative impact data at the time they apply for the OGDPs. Long term, additional actions may be necessary to ensure CIDER data are complete.

Finally, this report was compiled with contributions from the CDPHE's Air Pollution Control Division (APCD), Colorado Energy Office (CEO) and Colorado Parks and Wildlife (CPW), and supplements their reports and/or recent presentations to the Commission. The Commission appreciates their work, expertise, and contributions to the report.

904.a.(1) Data Gathered

Subparagraph 1 of 904.a. requires the Director to provide a report of data gathered in CIDER. CIDER is composed of data submitted on the complete Form 2B: Cumulative Impact Data Identification[1]. Some information provided on these forms are estimates as operators plan their OGDP Location and activity, and the associated actual values are provided to the COGCC or APCD after the activity is complete. Certain additional data submitted with the Application for Permit to Drill (Form 2) or Oil and Gas Location Assessment (Form 2A) may be referenced or incorporated in order to present information within this report.

Similar to last year, this report presents much of the information by operating area. With the addition of more OGDPs, the operating areas are broken out to better represent differences in well, basin, and operational characteristics. As a result, this information is presented with three additional operating areas: North Park, Southeast Plains, and Southwest Slope. The resulting operational areas are shown in Figure 1. The Southwest Slope includes the area near the San Juan Basin and has been pulled out of the West Slope. The West Slope continues to include western and northwestern Colorado, which include the Piceance Basin and Sand Wash Basin. The DJ Basin has been renamed to the Front Range to differentiate the differences between the eastern and western portions of the geologic DJ Basin, of which the former is included in Eastern Plains. Similarly, the Raton Basin area has been pulled out of the Eastern Plains and renamed as the Southeast Plains. Finally, North Park has been included as its own area to reflect the unique operating conditions of Jackson County; while there are no OGDPs approved to date in this area, statewide information will include this area. These changes to operating areas impact a couple of the OGDPs included in the 2021 Report on the Evaluation of Cumulative Impacts, and 2021 information included in this report reflects these new area designations.

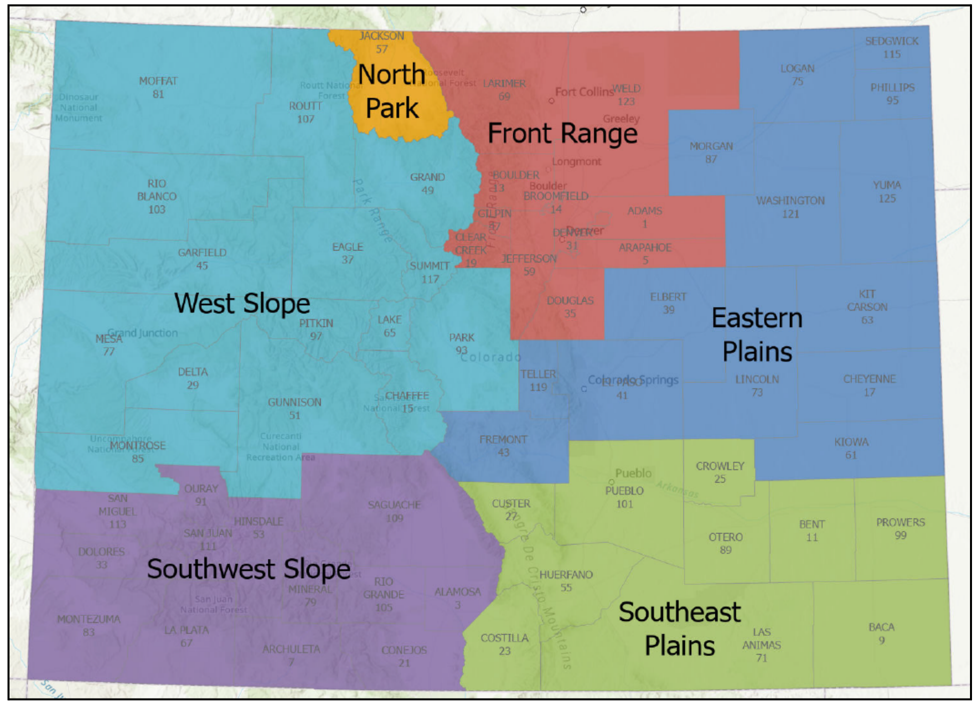


Figure 1: Report on Evaluation of Cumulative Impacts Operating Areas

[1] This Cumulative Impact report does not include approved partial Form 2Bs submitted pursuant to Rule 803.b.(2).A. This partial form includes some but not all of the information discussed in this report, and has been omitted here.

In 2022, 47 OGDPs were approved by the Commission and are included in this report. Unless otherwise stated, all charts in this report are for 2022 data only. These OGDPs include 77 new and or amended OGDP Locations and 838 wells. Approvals in 2022 include an increase in the average number of OGDP Locations per OGDP with the highest number in the Southeast Plains (Figure 4). The average number of wells[2] per location also saw an increase in 2022, and continues to be highest in the West Slope (Figure 6). The number of wells per OGDP Location can be driven by a number of factors, including geologic basins, mineral rights, density of existing development, regulatory spacing, etc.

Figure 2: Number of ODGPs Approved

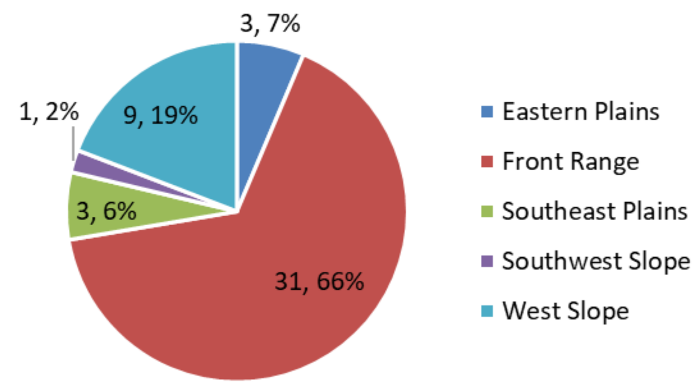


Figure 3: Number of Locations Approved

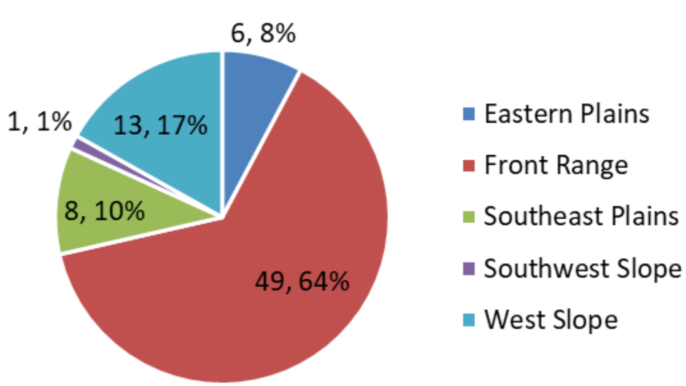
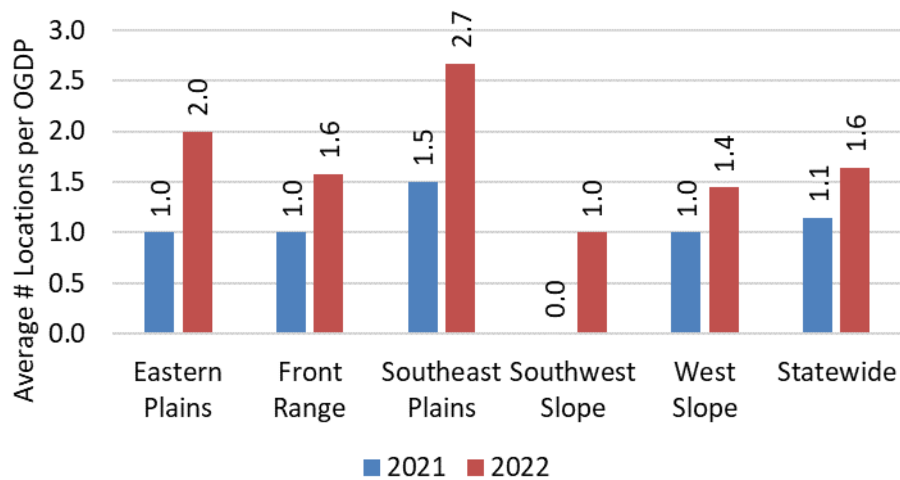
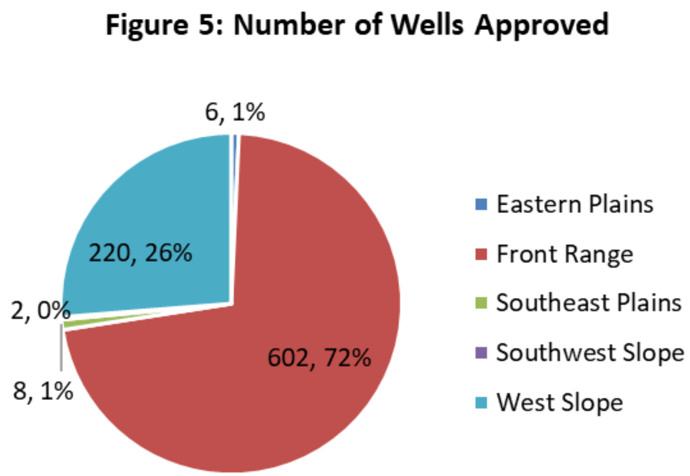
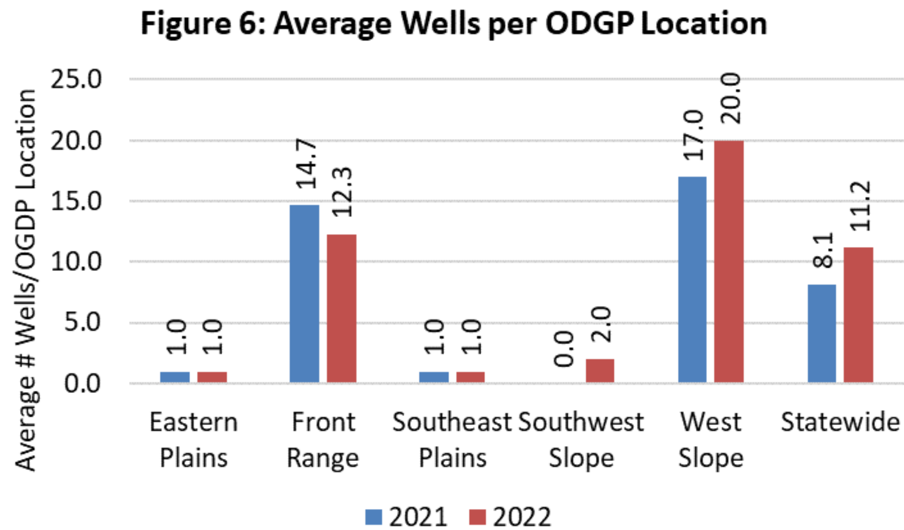


Figure 4: Average ODGP Locations per OGDP



[2] There were two OGDPs approved in 2022 without wells associated with them, both of which are water management facilities approved on the West Slope. The contribution from these OGDPs and/or OGDP Locations were excluded from all "per well" averages in this report.



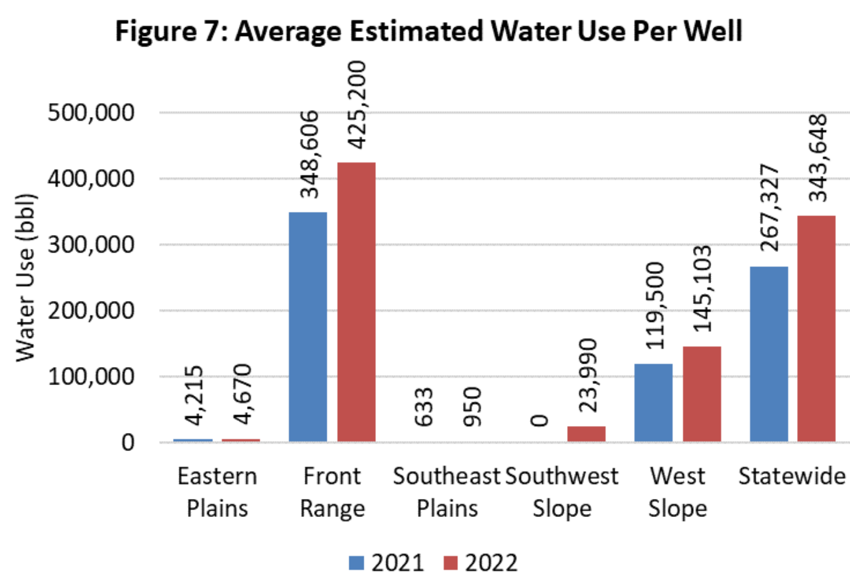


CIDER Data

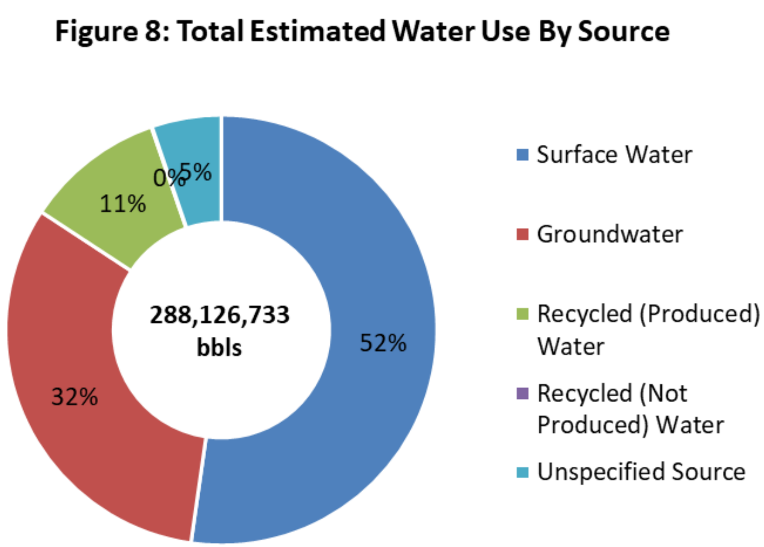
Water

Water Use

The average estimated planned water use for drilling and completions per well is greatest for the Front Range (Figure 7). Wells in this operating area are typically horizontal wells with long laterals, which require a lot of water to complete the well. The eight Southeast Plains wells associated with the three OGDPs are shallow helium wells drilled with air rotary drilling systems, and have no hydraulic fracturing or other completions planned, therefore, water use will be much lower for these wells than a traditional oil and gas well. The five Eastern Plains wells include single vertical well OGDP Locations approved under three OGDPs. Additional differences are expected to be driven by differing well design between operating areas (horizontal v. vertical, lateral length, depth, etc.).



Estimated planned water usage during drilling and completion activities is characterized by water source: surface water, groundwater, recycled water, and unspecified. The majority of estimated water used is from surface water, as shown in Figure 8. Approximately 89% of the total estimated water use from OGDPs approved in 2022 is in the Front Range, with approximately 11% in the West Slope and less than 0.1% in each of the other operating areas.



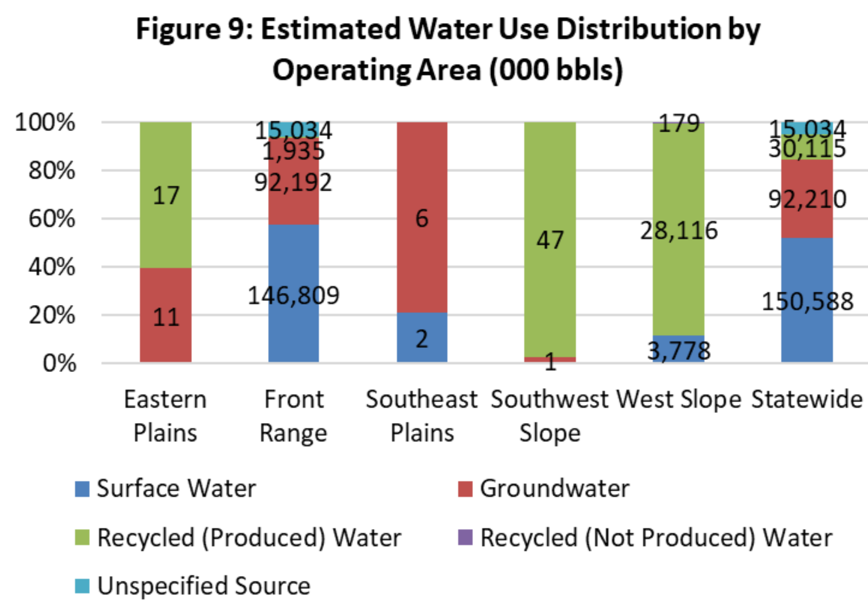
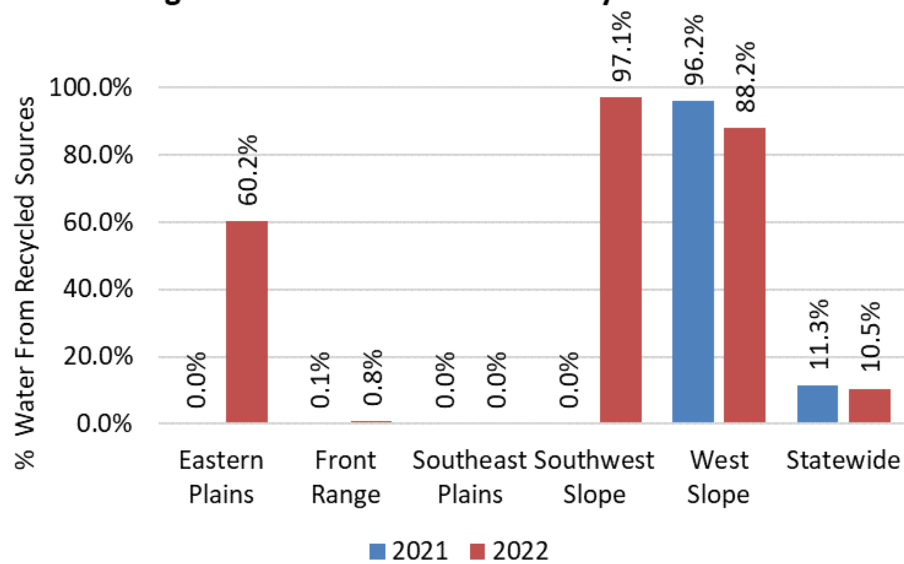


Figure 9 illustrates the proportion of estimated water usage by source in each operating area. Operators in the Front Range primarily use surface water, which drives the statewide estimated surface water use. The Southeast Plains operators primarily source from groundwater, and Eastern Plains, Southwest Slope, and West Slope operators all plan the majority of their use from recycled produced water. Seven OGDPs included estimated water volume from a source listed as unspecified, and all of these are located in the Front Range and come from municipal water sources, which can be a combination of ground and surface water.

In 2022, the COGCC, under the leadership of Commissioner Messner, partnered with the Colorado School of Mines to convene the Colorado Produced Water Consortium (CPWC). This consortium aims to bring diverse stakeholders together to address produced water challenges with the goal of increasing the reuse of produced water both inside and outside of the oilfield. The low use of recycled produced water in the Front Range, as shown in Figure 10, is an example of one of the issues to be discussed by the CPWC. The CPWC will also be addressing how the water used for these activities can be recycled for other uses within the oilfield. Commissioners have requested that this report look closely at the actual disposition of the water used to drill and complete wells. Staff is considering potential changes to forms and/or regulations to accomplish this goal. In the meantime, the use of this water will continue to be addressed by the CPWC.

Figure 10: Estimated Percent Recycled Water

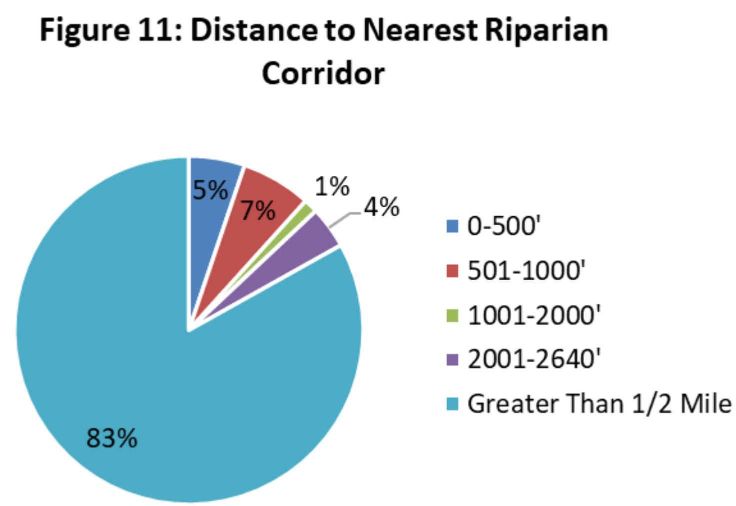


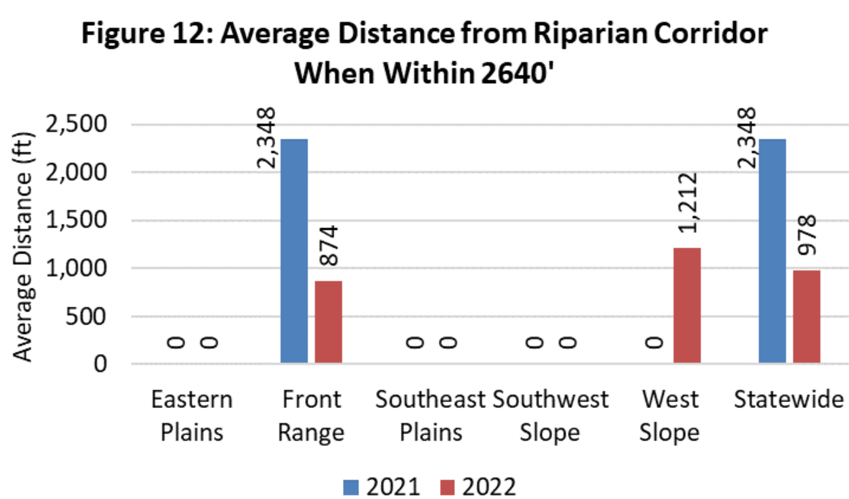
Future reports will include the actual water used as reported pursuant to Rule 431.b when available. *The future ability to compare actuals to estimates will be perhaps one of the most powerful tools for the evaluation of cumulative impacts that the COGCC has.* These volumes are reported by well on the associated Form 5s (Drilling and Completions Report) and Form 5As (Completed Interval Report). The Form 5s are required to be submitted 60 days after the rig is released from the OGDP Location, and the Form 5As are required to be submitted 30 days after (re)stimulation or a productivity test if there was no stimulation. At the time this report was prepared, there were only two approved Form 5s with actual water use for wells for which there is associated CIDER data (i.e. wells associated with OGDPs approved since January 2021)[3]. The water volume reported on these two Form 5s were for the partial drilling of two wells which were later plugged and abandoned (PAd). Future Reports on the Evaluation of Cumulative Impacts will continue to assess the availability of this information, and include a comparison of the estimated water use in CIDER with actual reported water use on Form 5s and 5As when enough information is available.

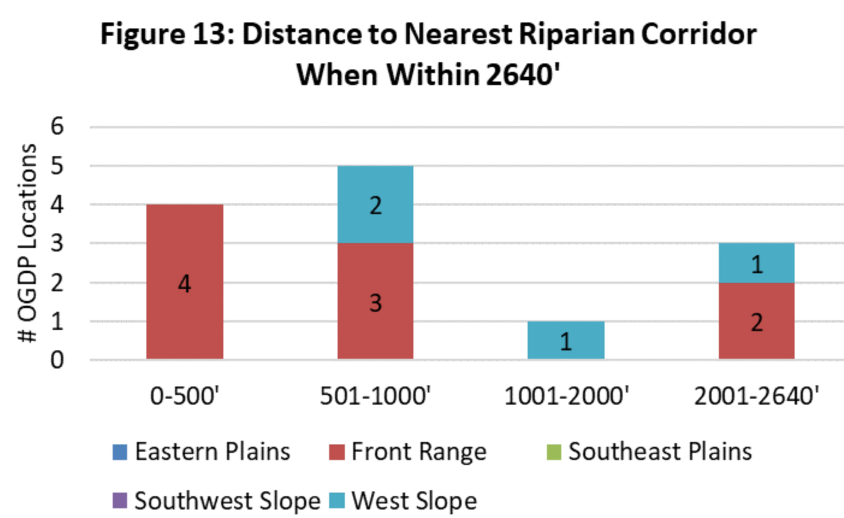
[3] Additional Forms 5 and 5A may have been submitted prior to this report, but the information in those forms has not yet been reviewed by Staff, and the forms may still be in process.

Water Resources

Only 13 (17%) OGDP Locations approved in 2022 are within half of a mile from a riparian corridor (Figure 11). When an OGDP Location is within half of a mile from a riparian corridor, Figure 12 shows the average distance to the corridor; the Front Range has OGDP Locations nearest to riparian corridors, on average. The majority of OGDP Locations approved in 2022 within half of a mile of a riparian corridor are within 501-1000 feet. (Figure 13).







Forty-five (58%) OGDP Locations approved in 2022 are within half of a mile from a wetland (Figure 14). When an OGDP Location is within half of a mile from a wetland, Figure 15 shows the average distance to the wetland; the Front Range has OGDP Locations nearest to wetlands on average. The majority of OGDP Locations approved in 2022 within half of a mile of a wetland are within 500 feet (Figure 16).

Figure 14: Distance to Nearest Wetland

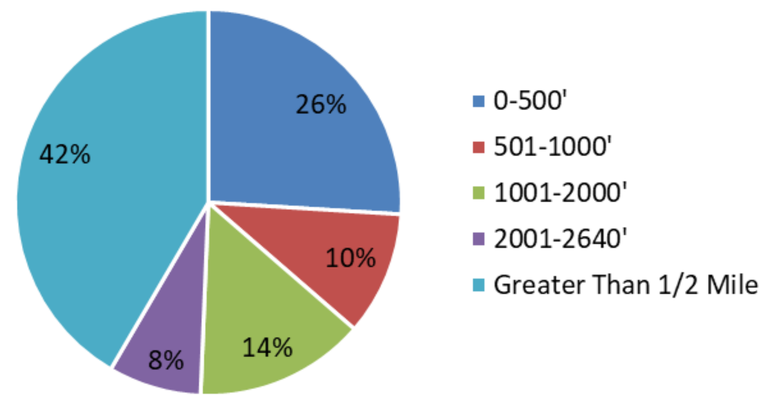


Figure 15: Average Distance from Wetland When Within 2640'

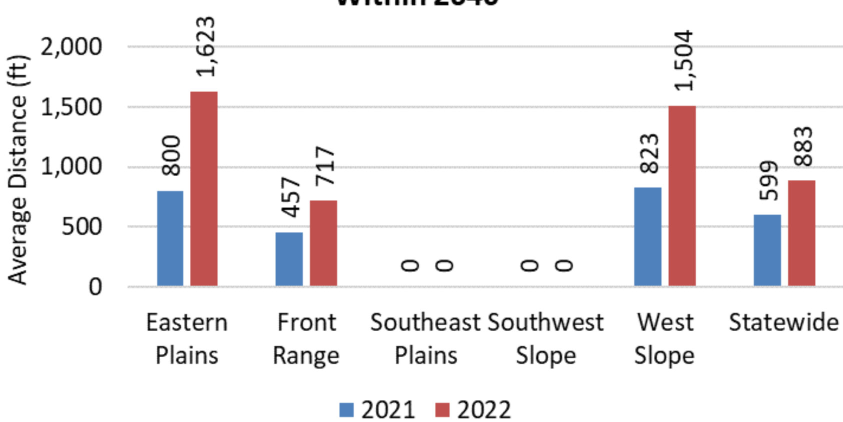
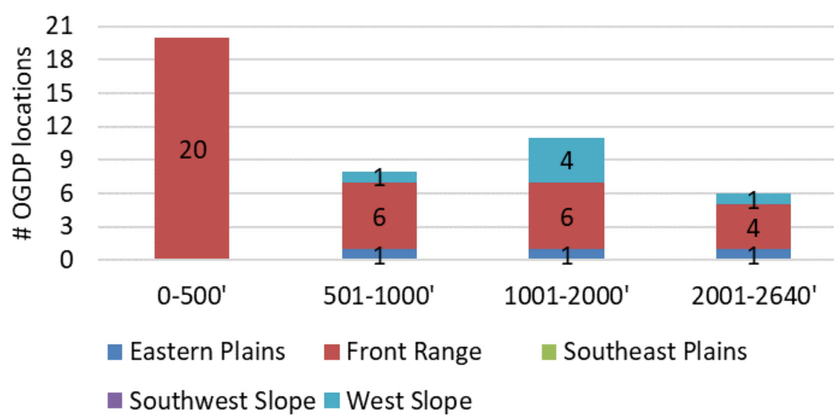


Figure 16: Distance to Nearest Wetland When Within 2640'



Sixty-two (81%) OGDP Locations approved in 2022 are within one half of a mile from a Water of the State[4] (Figure 17). When an OGDP Location is within half of a mile from a Water of the State, Figure 18 shows the average distance to the Water of the State; the Southwest Slope has OGDP Locations nearest to Water of the State on average. The majority of OGDP Locations approved in 2022 within half of a mile of a Water of the State are within 500 feet (Figure 19).

Only one OGDP Location approved in 2022 is within one mile of a public water system intake.

Figure 17: Distance to Nearest Water of the State

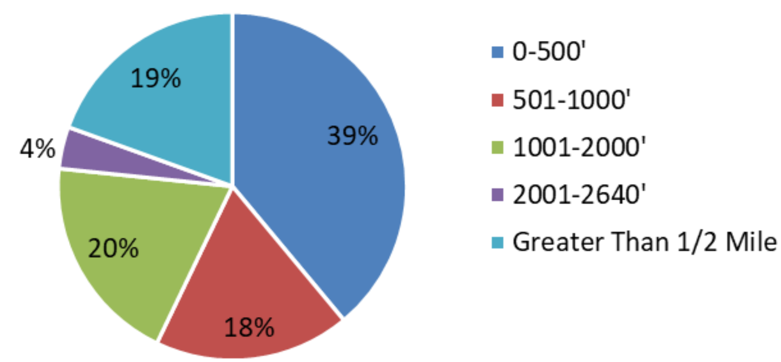


Figure 18: Average Distance from Water of the State When Within 2640'

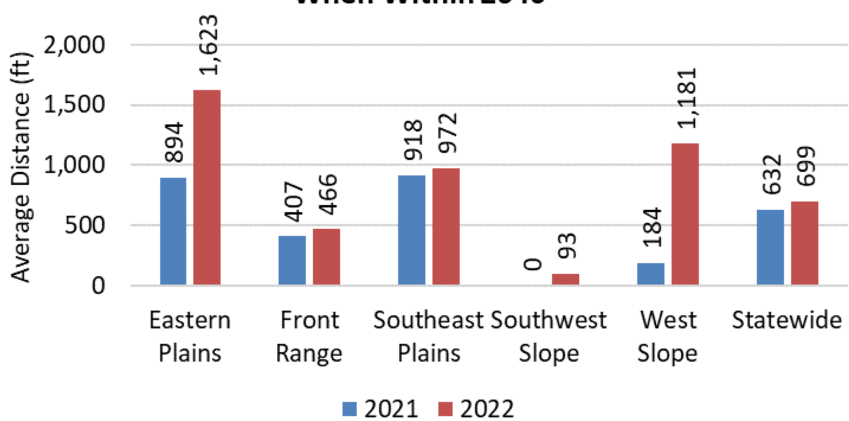
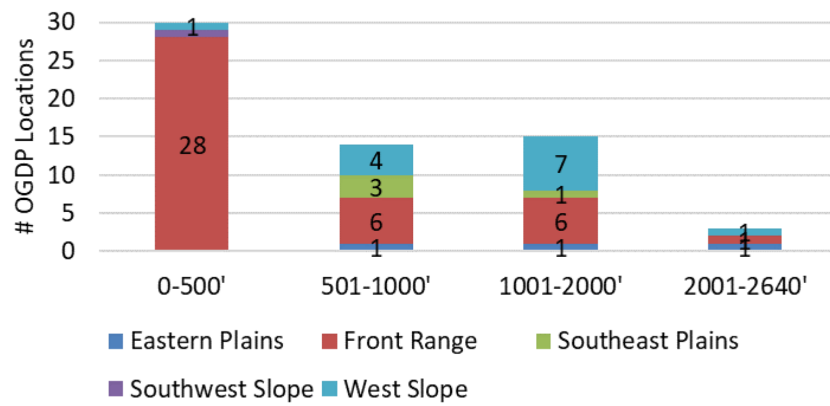


Figure 19: Distance to Nearest Water of the State When Within 2640'



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[4] COGCC 100 Series Definitions: WATERS OF THE STATE mean any and all surface and subsurface waters which are contained in or flow in or through this state, but does not include waters in sewage systems, waters in treatment works of disposal systems, water in potable water distribution systems, and all water withdrawn for use until use and treatment have been completed. Waters of the state include, but are not limited to, all streams, lakes, ponds, impounding reservoirs, wetlands , watercourses, waterways, wells, springs, irrigation ditches or canals, drainage systems, and all other bodies or accumulations of water, surface and underground, natural or artificial, public or private, situated wholly or partly within or bordering upon the State.

Liquid Product Storage

The average tank storage capacity is reviewed on a per- location and per-well basis for all OGDP Locations approved and OGDP Locations that had at least one Residential Building Unit (RBU) within 2,000 feet.

The average oil/condensate capacity per OGDP Location is greatest in the Front Range for OGDPs approved in 2022 (Figure 20). The average oil/condensate capacity per well is greatest in the Eastern Plains (Figure 22), with the difference due to the lower number of wells per OGDP Location in this operating area compared to the Front Range.

When an OGDP has at least one RBU within 2,000 feet, the statewide oil/condensate storage capacity decreases both by OGDP Location (Figure 21) and by well (Figure 23). There is a notable decrease in the Front Range in 2022 (1,337 bbls of condensate/oil storage averaged over all Front Range OGDP Locations reduced to 404 bbls of condensate/oil storage averaged over OGDP Locations proximal to an RBU). The West Slope only approved one OGDP where at least one RBU is within 2,000 feet, so more data points are necessary to determine whether this one value is indicative of the region.

Produced water storage capacity per OGDP Location approved in 2022 is greatest on the West Slope (Figure 24), primarily due to the large produced water tank volume at the two OGDPs for water management facilities, which are not included in the per well averages in Figure 26. The average produced water capacity per well for OGDP Locations approved in 2022 is greatest on the Southwest Slope (Figure 26).

Figure 20: Average OGDP Location Oil/Condensate Storage Capacity

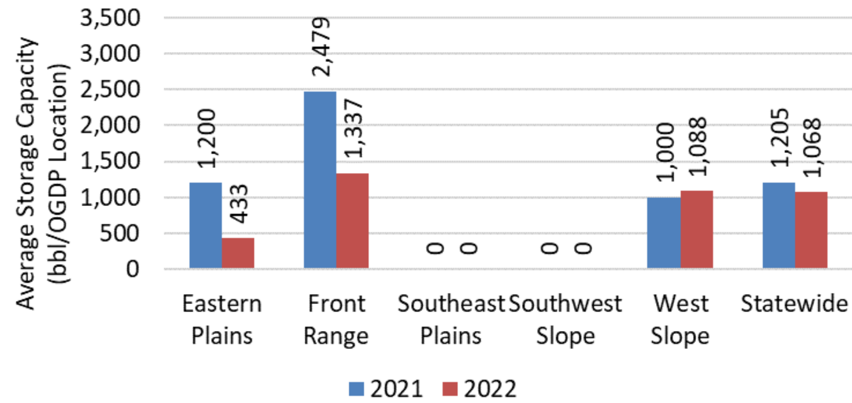
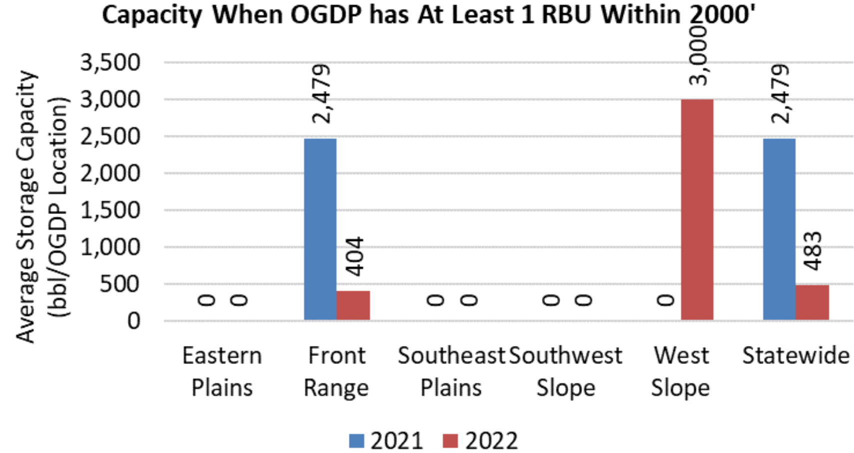


Figure 21: Average OGDP Location Oil/Condensate Storage Capacity When OGDP has At Least 1 RBU Within 2000'



The average produced water storage capacity when the OGDP had at least one RBU within 2,000 feet remains the same or decreases both by OGDP Location (Figure 25) and by well (Figure 27).

Figure 22: Average Oil/Condensate Storage Capacity Per Well

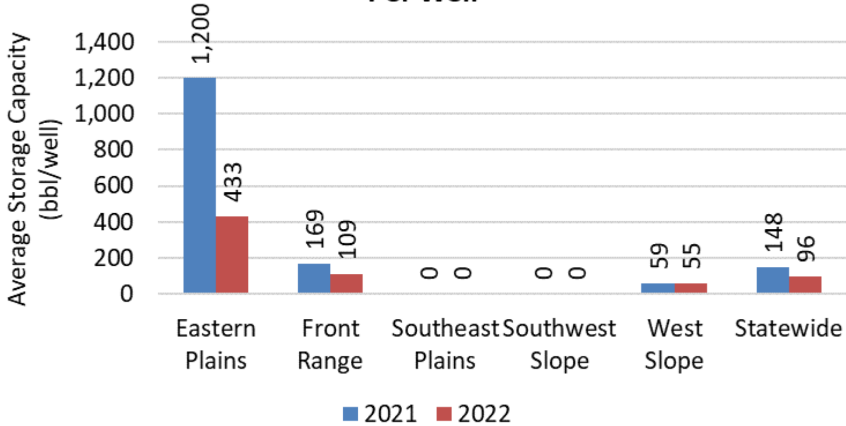


Figure 23: Average Oil/Condensate Storage Capacity When OGDP has At Least 1 RBU Within 2000' Per Well

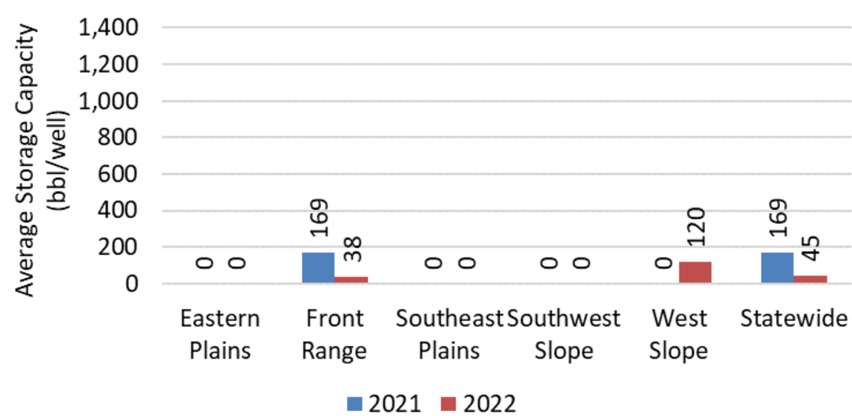


Figure 24: Average OGDP Location Produced Storage Water Capacity

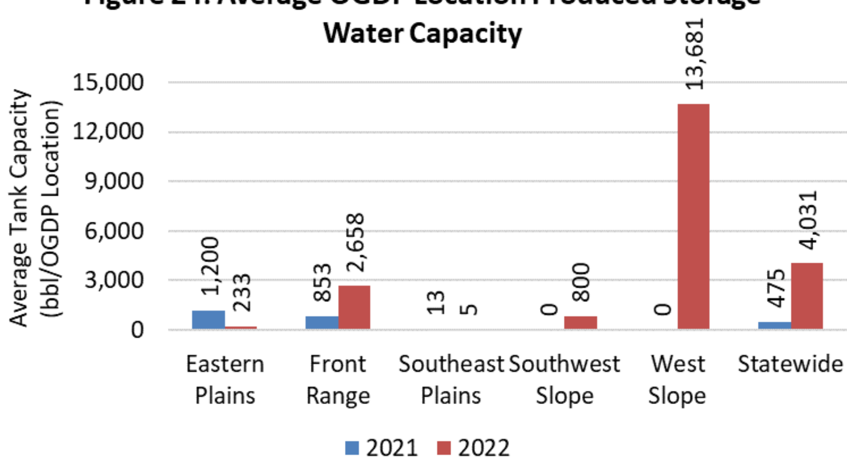


Figure 25: Average OGDP Location Produced Water Storage Capacity When OGDP has At Least 1 RBU Within 2000'

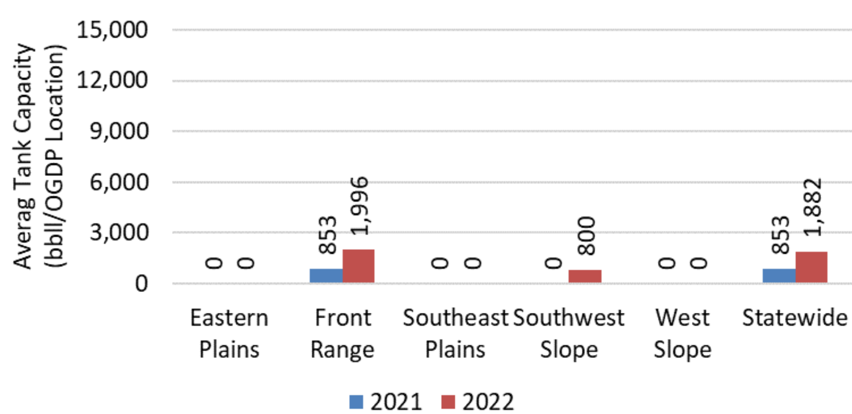


Figure 26: Average Produced Water Storage Capacity Per Well

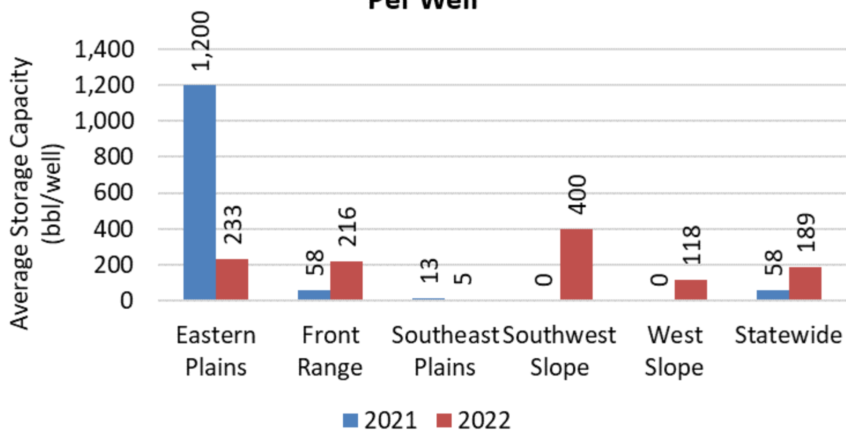
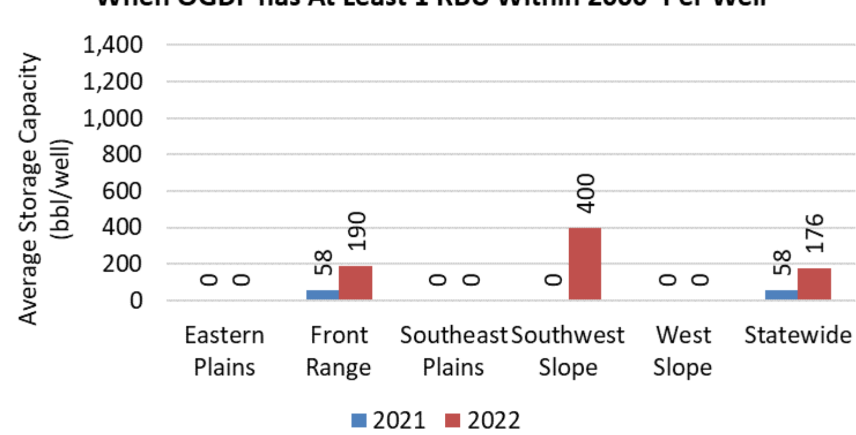


Figure 27: Average Produced Water Storage Capacity When OGDP has At Least 1 RBU Within 2000' Per Well



Land Use

Surrounding Land Use

The surrounding land use data provide information about the land uses within a one-mile radius of an OGDP Location[5] at the time of OGDP approval. Land use is categorized into three types: crop land, non-crop land, and subdivided. Crop land is further categorized into irrigated, non-irrigated, and Conservation Reserve Program (CRP). Non-crop land is defined as land that is not being used to cultivate or harvest crops, and is not formally subdivided as industrial, commercial, or residential. The four non-crop land categories are rangeland, forestry, recreational, and other. Finally, subdivided is further categorized as industrial, commercial, and residential.

[5] This information is reported in acres. A circle with a one-mile radius is approximately 2010 acres.

Figure 28: Statewide Land Use within 1 Mile of OGDP Location

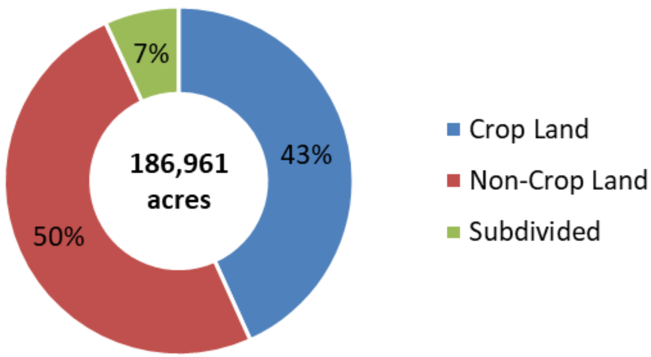
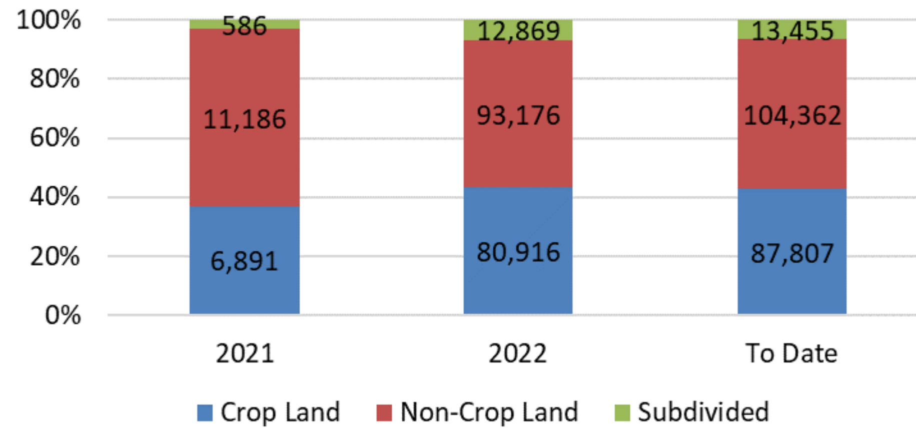


Figure 29: Distribution of Statewide Land Use within 1 Mile of OGDP Location (acre)



Non-crop land is the majority of reported land use within one mile of the OGDP Locations approved in both 2021 and 2022[6] as shown in Figure 28 above. Operators reported that 50 percent of the land within one mile of the OGDP Locations approved in 2022 is non-crop land compared to the 60 percent that surrounded locations approved in 2021 (Figure 29). The reported percentage of subdivided land within one mile of the OGDP Locations approved in 2022 is seven percent compared to three percent in 2021. The land surrounding the OGDP Locations in the Front Range operating area is primarily crop land, while the OGDP Locations in the other operating areas is primarily non-crop land (Figure 30). A little over half of the subdivided lands is classified as residential (Figure 33), and are all located on the Front Range.

[6] Should OGDP Locations be located within one mile of each other, some of this surrounding land may be double-counted in these charts and metrics.

Figure 30: Distribution of Land Use within 1 Mile of OGDP Location by Operating Area (acre)

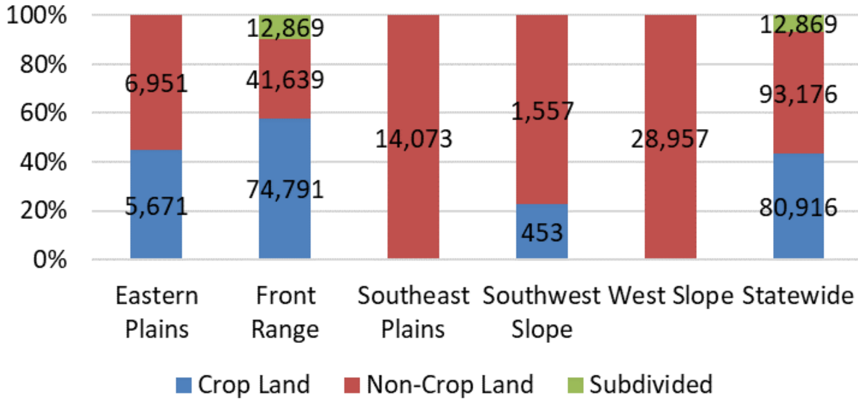


Figure 31: Distribution of Crop Land within 1 Mile of OGDP Location by Operating Area (acre)

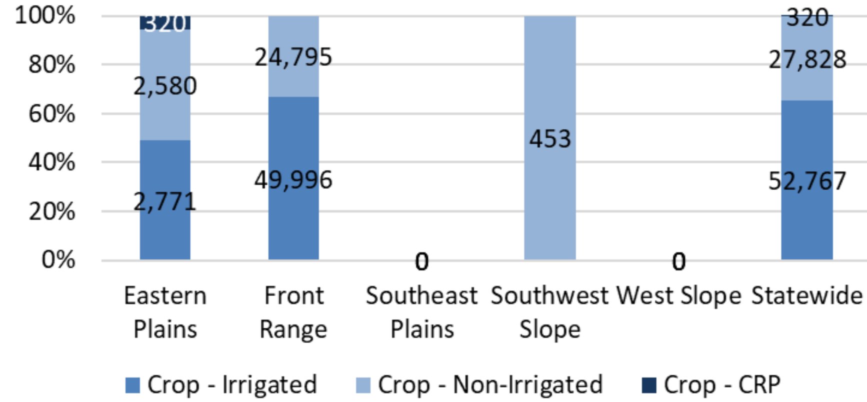


Figure 32: Distribution of Non-Crop Land within 1 Mile of OGDP Location by Operating Area (acre)

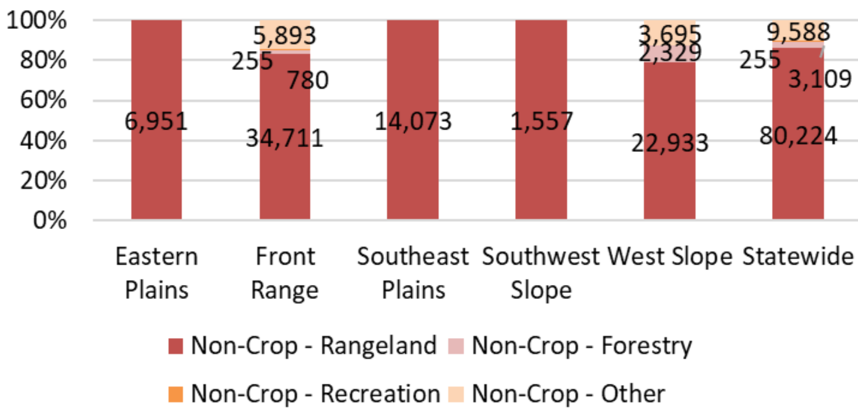
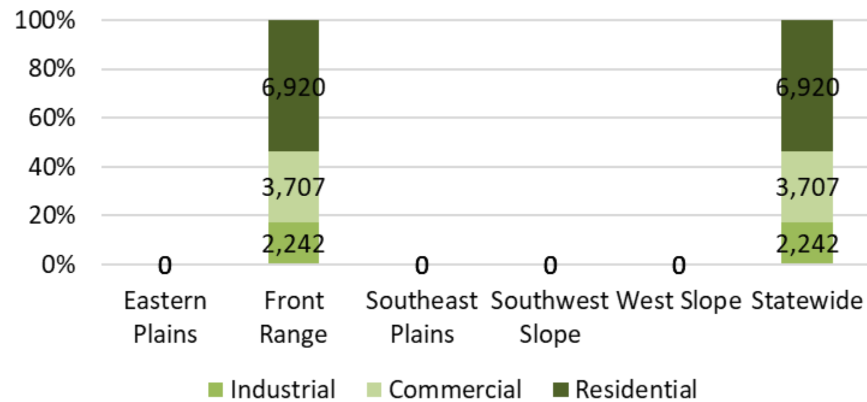


Figure 33: Distribution of Subdivided Land within 1 Mile of OGDP Location by Operating Area (acre)



Surface Disturbance

Information in this section is reported in three ways: total surface disturbance, OGDP Location disturbance, and access road, pipeline corridor, and utility corridor disturbance. The total surface disturbances are the sum of the OGDP Location disturbance area and the access road, pipeline corridor, and utility corridor disturbance. Surface disturbances are provided as both construction disturbance and the post-interim reclamation disturbance and is expected to be the greatest during the construction phase. After interim reclamation has occurred, the remaining disturbed area (the production surface) will be the disturbance that exists for the longest period of time. The access road, pipeline corridor, and utility corridor disturbances are collected at the OGDP Level to reflect their shared use within all locations at the OGDP. Therefore, total surface disturbances are only averaged per well, OGDP Location surface disturbances are also averaged per OGDP Location, and access road, pipeline corridor, and utility corridor disturbances are also averaged per OGDP.

The total construction and post-interim reclamation disturbances for OGDPs approved in 2022 are 1,215.8 acres and 512.8 acres, respectively, and the distribution between operating areas is included in Figure 34 and Figure 35 below. The average total surface disturbance per well is greatest in the Southeast Plains for both construction (Figure 36) and post-interim reclamation (Figure 37). The Southeast Plains' largest total disturbance per well is due to the rural nature of the locations. The lack of existing infrastructure requires an increase in disturbance for access roads and pipelines per well. One OGDP with two locations required a longer access road for each location with one well per location, which is the primary contributor to this per well average being so high. The locations in the Southeast Plains area are relatively small post-interim reclamation, but the lack of existing infrastructure and remote setting distort the per well average.

Figure 34: Total Construction Surface Disturbance

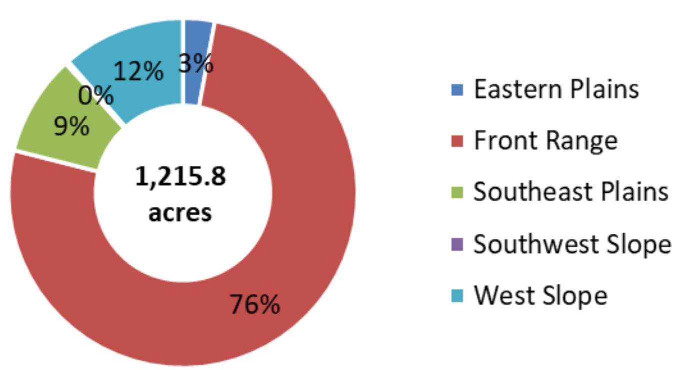


Figure 35: Total Surface Disturbance After Interim Reclamation

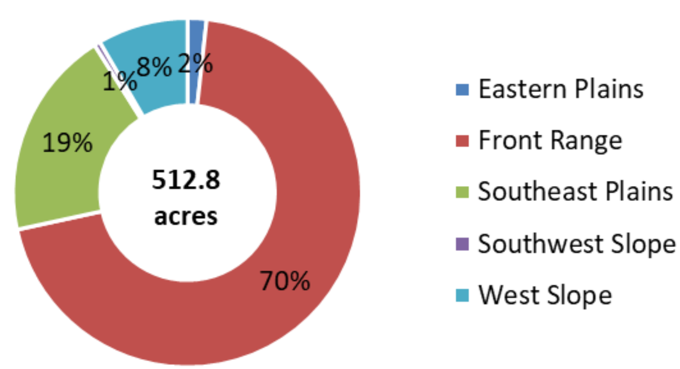


Figure 36: Average Total Construction Disturbance Per Well

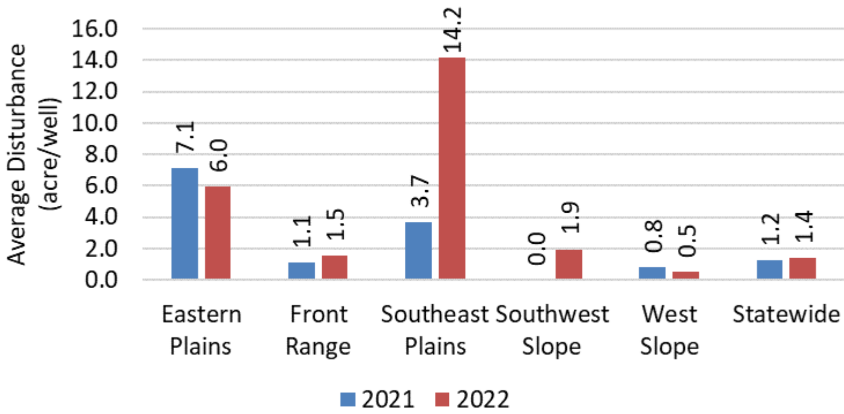
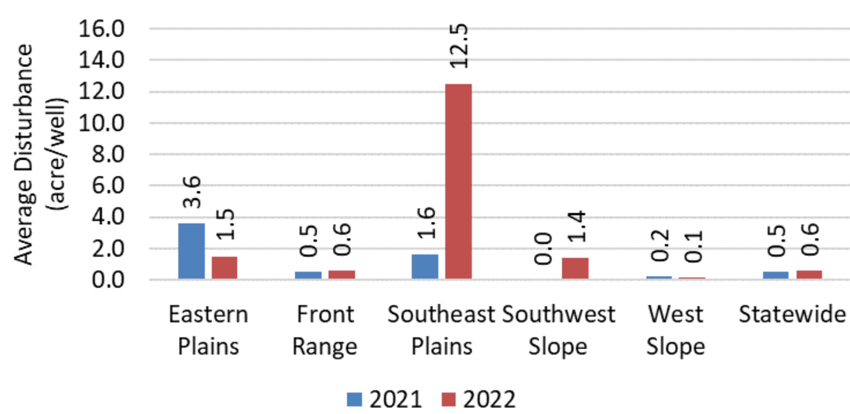


Figure 37: Average Total Disturbance After Interim Reclamation Per Well



The OGDP Location construction and post-interim reclamation disturbances for OGDP Locations approved in 2022 are 816.5 acres and 344.2 acres, respectively, and the distribution between operating areas is included in Figure 38 and Figure 39 below. The majority (93%) of the OGDP Location construction surface disturbance is located on privately owned surface (Figure 40)[7]. The 4% of the OGDP Location construction surface disturbance on Federal land is located on the West Slope, and the 3% on State Lands is primarily on the Southeast Plains with a little on the Front Range (Figure 41). The average OGDP Location per well construction disturbance is greatest in the Eastern Plains (Figure 44) and disturbance post-interim reclamation is greatest on the Southwest Slope (Figure 45). This is expected to be due to the low number of wells per location in these areas compared to the larger average surface disturbance and significantly larger well count per OGDP Location on the Front Range (Figures 42 and 43).

[7] Because the surface owner type is reported by location on the Form 2A, it was only included for OGDP Location surface disturbances. While the surface owner type for OGDPs approved in 2022 does not differ by location within an OGDP, which would allow the application of this field to the access road, pipeline corridor, and utility corridor disturbance, the same cannot be guaranteed for future OGDPs.

Figure 38: OGDP Location Construction Disturbance by Basin

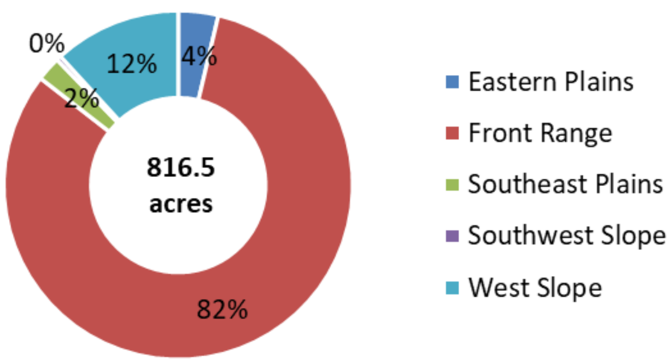


Figure 39: ODGP Location Disturbance After Interim Reclamation by Basin

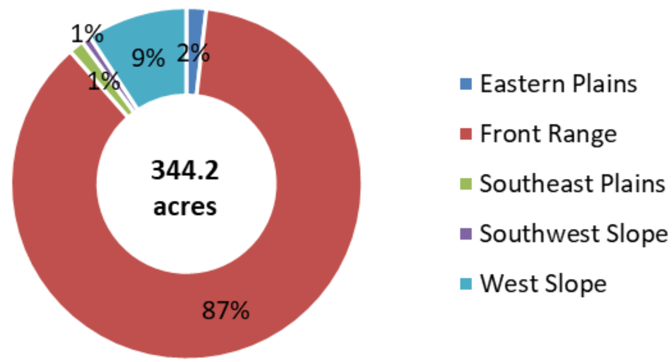


Figure 40: OGDP Location Construction Disturbance Surface Ownership Type

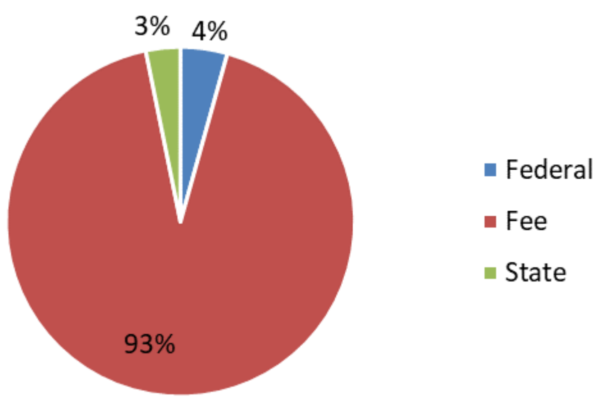
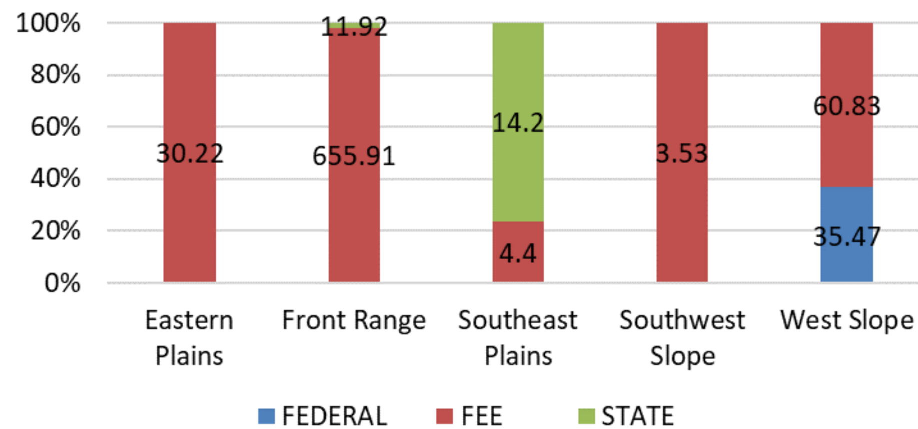


Figure 41: OGDP Location Construction Disturbance by Surface Ownership Type (acre)



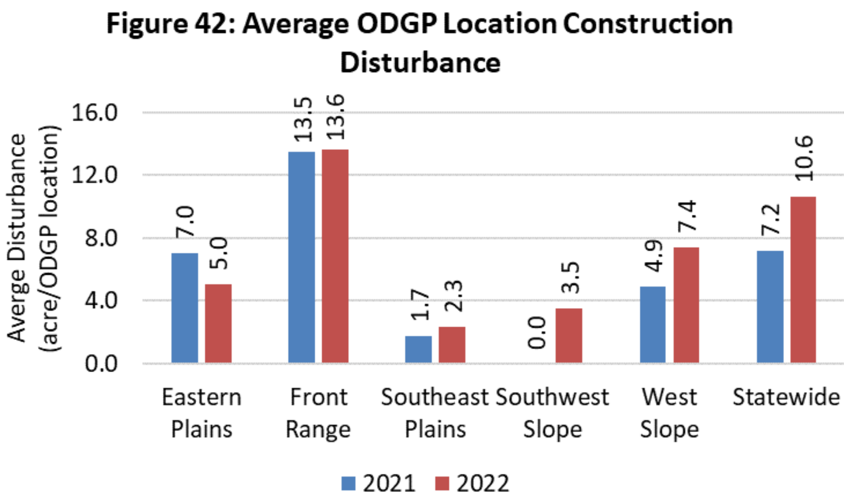


Figure 42: Average ODGP Location Construction Disturbance
Averge Disturbance (acre/ODGP location)
16.0
12.0
8.0
4.0
0.0
7.0
5.0
13.5
13.6
1.7
2.3
0.0
3.5
4.9
7.4
7.2
10.6
Eastern Plains
Front Range
Southeast Plains
Southwest Slope
West Slope
Statewide
2021
2022

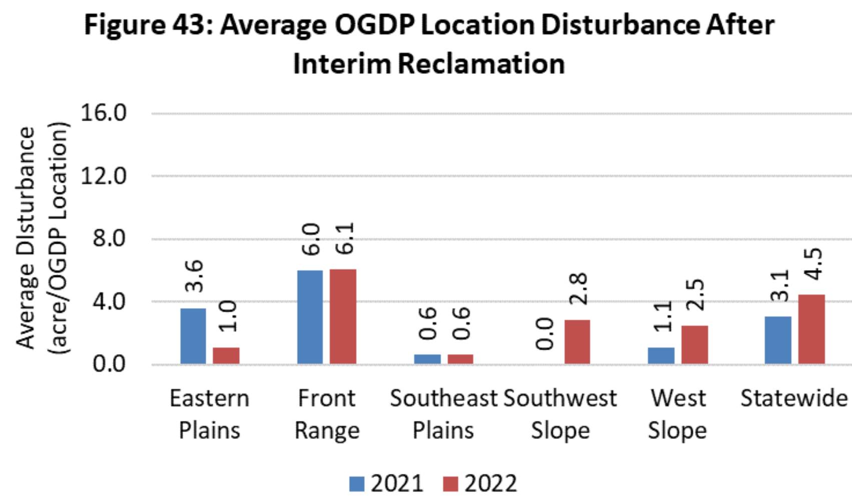


Figure 43: Average OGDP Location Disturbance After Interim Reclamation
Average DIsturbance (acre/OGDP Location)
16.0
12.0
8.0
4.0
0.0
3.6
1.0
6.0
6.1
0.6
0.6
0.0
2.8
1.1
2.5
3.1
4.5
Eastern Plains
Front Range
Southeast Plains
Southwest Slope
West Slope
Statewide
2021
2022

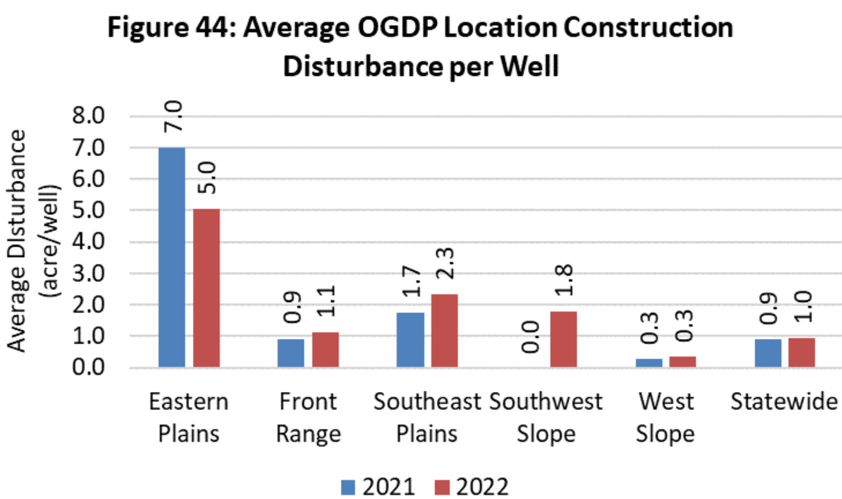


Figure 44: Average OGDP Location Construction Disturbance per Well
Average DIsturbance (acre/well)
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
7.0
5.0
0.9
1.1
1.7
2.3
0.0
1.8
0.3
0.3
0.9
1.0
Eastern Plains
Front Range
Southeast Plains
Southwest Slope
West Slope
Statewide
2021
2022

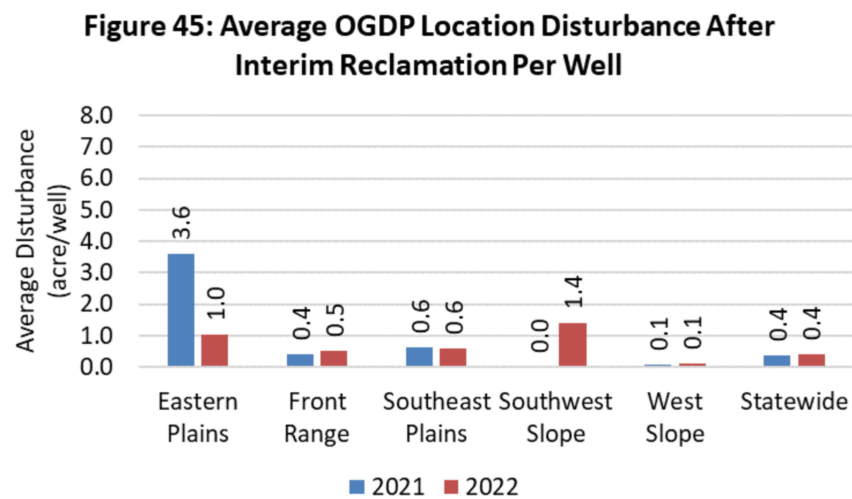


Figure 45: Average OGDP Location Disturbance After Interim Reclamation Per Well
Average DIsturbance (acre/well)
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
3.6
1.0
0.4
0.5
0.6
0.6
0.0
1.4
0.1
0.1
0.4
0.4
Eastern Plains
Front Range
Southeast Plains
Southwest Slope
West Slope
Statewide
2021
2022

The access road, pipeline corridor, and utility corridor construction and post-interim reclamation disturbances for OGDPs approved in 2022 are 387.0 acres and 167.3 acres, respectively, and the distribution between operating areas is included in Figure 46 and Figure 47 below. The average total surface disturbance per well is greatest in the Southeast Plains for both construction (Figure 50) and post-interim reclamation (Figure 51) disturbances. As described above, lack of existing infrastructure resulted in a larger disturbance required by the access roads in these rural locations for a couple of single well locations, distorting this per well average.

Figure 46: Access Road/Pipeline/Utility Construction Disturbance

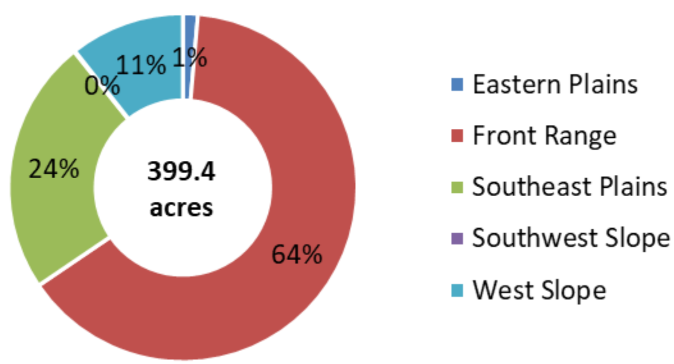


Figure 47: Access Road/Pipeline/Utility Disturbance After Interim Reclamation

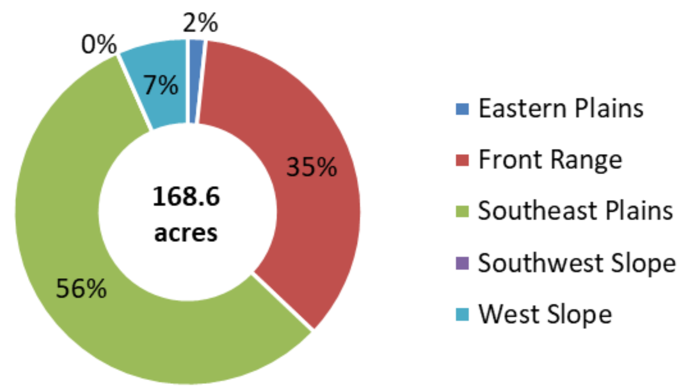


Figure 48: Average Road/Pipeline/Utility Construction Disturbance Per OGDP

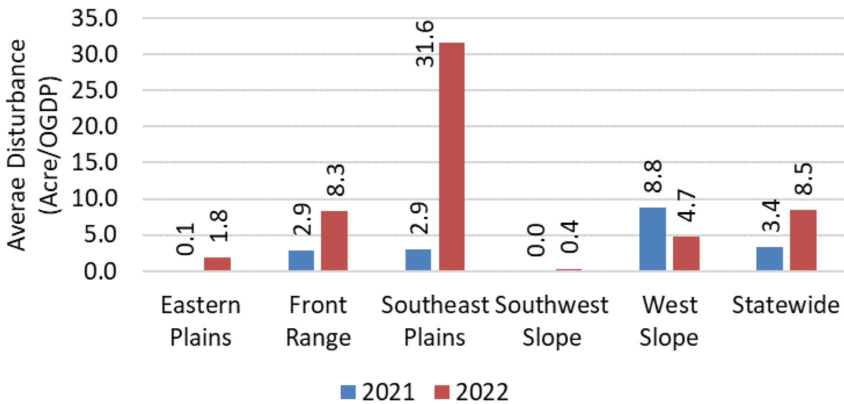


Figure 49: Average Road/Pipeline/Utility Disturbance After Interim Reclamation Per OGDP

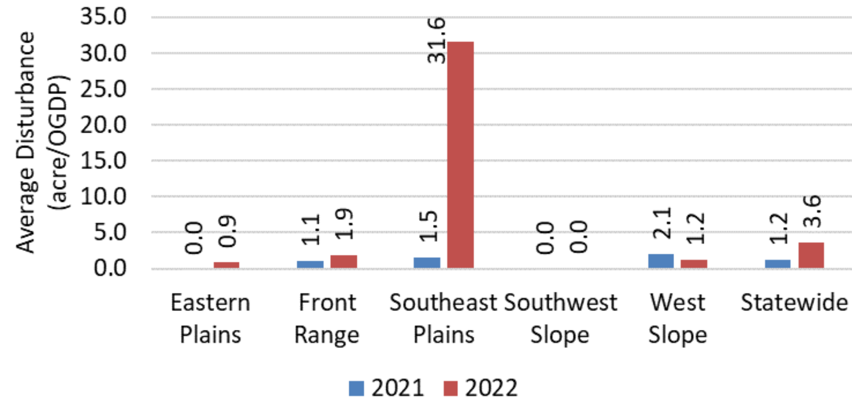


Figure 50: Average Road/Pipeline/Utility Construction Disturbance Per Well

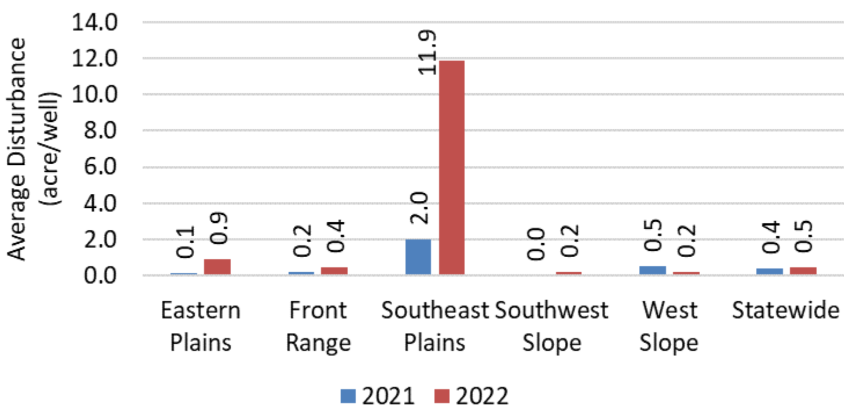
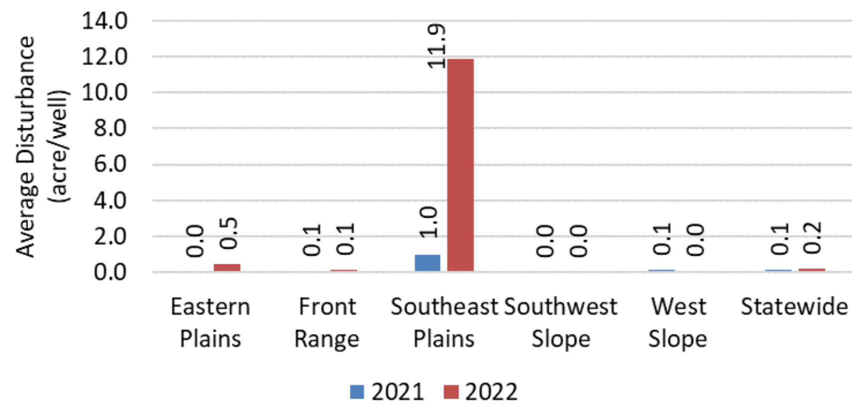


Figure 51: Average Road/Pipeline/Utility Disturbance After Interim Reclamation Per Well



Residential Building Units

Of the 77 OGDP Locations approved in 2022, 54 (70%) include at least one RBU within one mile of the OGDP Location (Figure 52). As shown in Figure 53, more OGDP Locations are approved where the nearest RBU is farther away from the OGDP Location. All of the locations with at least one RBU within 1,000 feet are permitted in the Front Range. This is expected to be due to the higher population density in the region.

Figure 52: Distribution of OGDP Location Distance to Nearest RBU

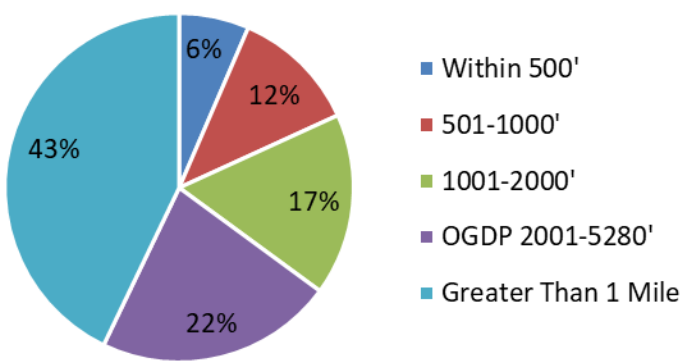
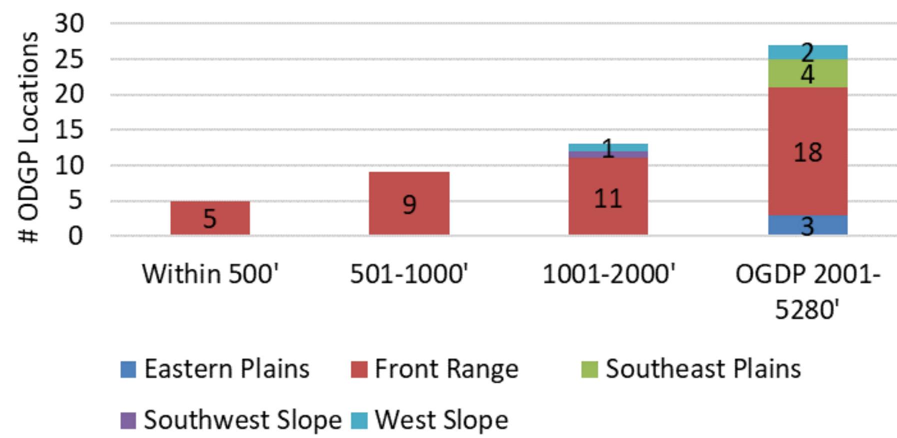


Figure 53: Distribution of OGDP Location Distance to Nearest RBU By Basin When Within 5280'



There are a total of 1,822 RBUs within one mile of OGDP Locations approved in 2022 (Figure 54). The Front Range is the most densely populated operational area, therefore 98% of these RBUs are in the Front Range. However, of the RBUs within a mile of OGDP Locations approved in 2022, only 8% of the total RBUs and 8% of the RBUs in the Front Range are within 2,000 feet as shown in Figures 54 and 55 below. Only one OGDP Location was approved within one mile of any High Occupancy Building Units (HOBU); these HOBUs are also a School Property with three separate buildings and are greater than 2000 ft from the approved OGDP Location. There are no Child Care Centers located within one mile of an approved OGDP Location.

Figure 54: Spacial Distribution of RBUs Within 1 Mile of OGDP Locations

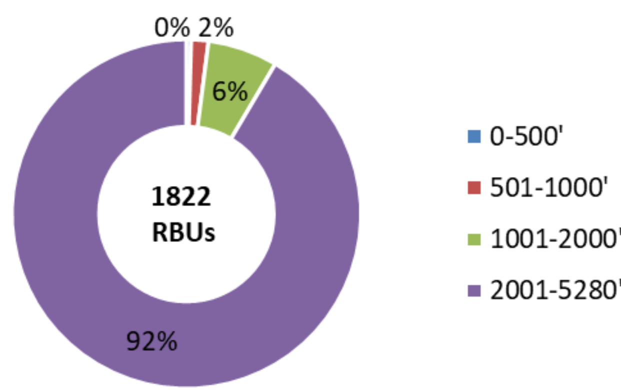
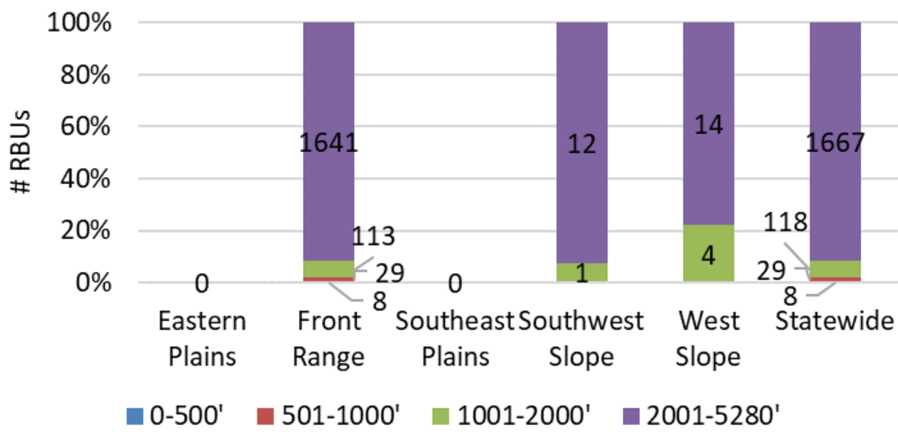


Figure 55: Distribution of RBUs Within 1 Mile of an OGDP Location



Disproportionately Impacted (DI) Communities are communities of color, low-income, or indigenous populations in the state that potentially experience disproportionate environmental or socioeconomic impacts and risks, and are further defined in the COGCC 100 Series Rules. For OGDP Locations proposed within a DI Community, additional protections are required and the public comment/CDPHE consultation periods are extended. For Locations proposed within 2,000 feet of a RBU in a DI Community, applicants must also provide a Community Outreach Map and a DI Community Map. Figure 58 shows a map of DI Communities and OGDP Locations approved in 2022. Eight of the 77 (10%) new or amended OGDP Locations approved in 2022 are within a DI Community, four of which are located on the West Slope (Figure 56 and Figure 57). The four West Slope Locations have no RBUs within one mile of any of the Locations. Of the three Front Range Locations, one operator obtained signed informed consent from the single RBU owner within 2,000 feet of the Location; two Locations had no RBUs within 2,000 feet of the Location. The Location in the Southwest Slope is an expansion of an existing Location with one RBU within 2,000 feet; the operator obtained signed informed consent from this resident.

Figure 56: Number of OGDP Locations Approved Within DI Community

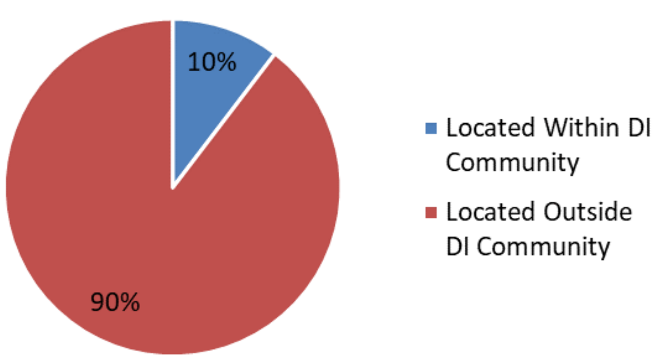
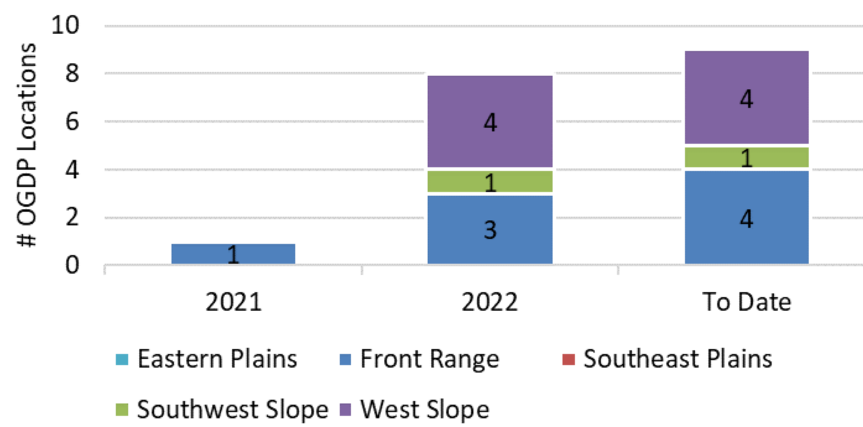


Figure 57: Number of OGDP Locations Approved Within DI Community



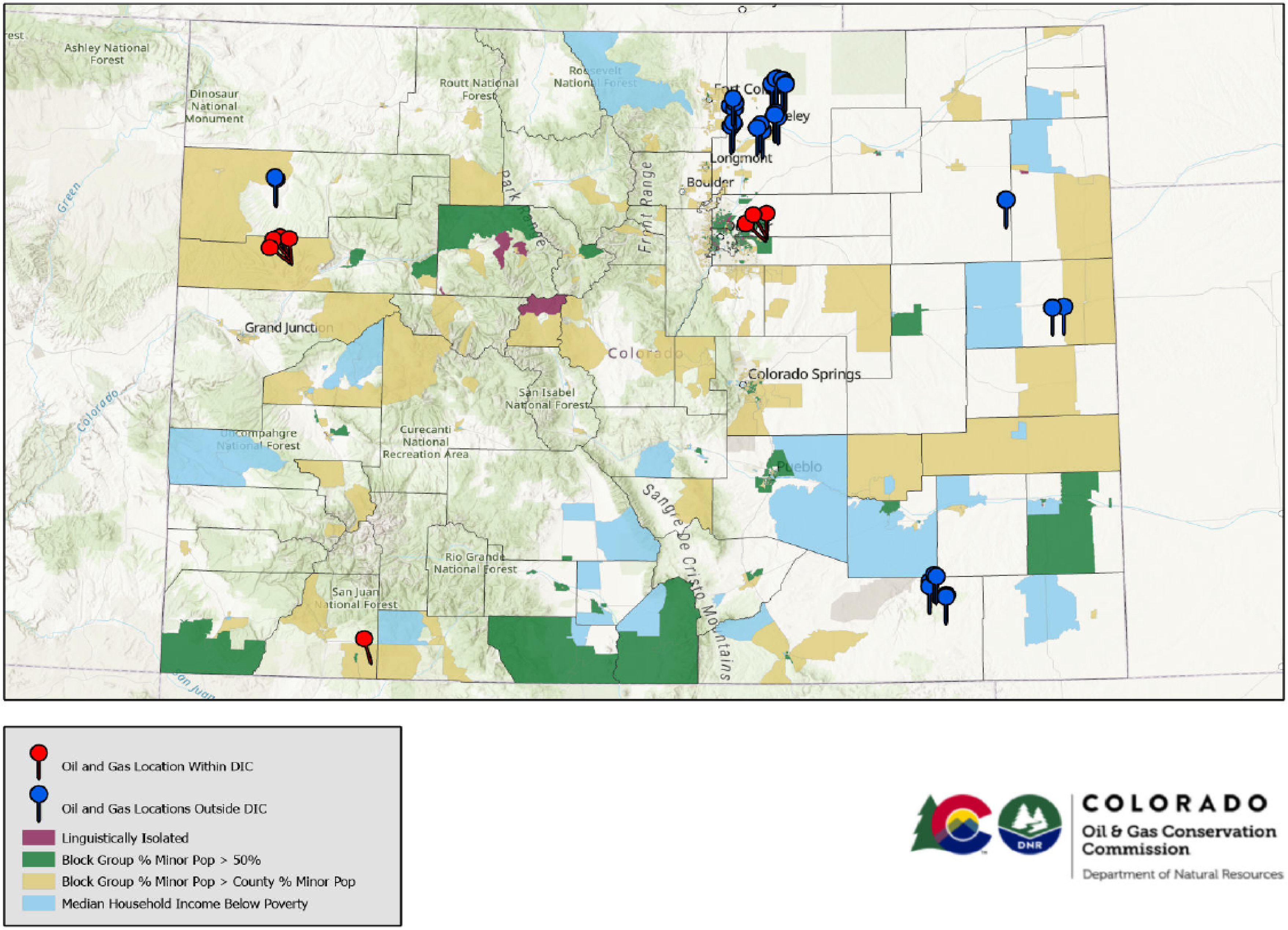


Figure 58: 2022 OGDP Locations Mapped with DI Communities

The information provided about existing oil and gas development near planned OGDP Locations can be used to identify areas of dense or sparse development. To generally assess existing density of oil and gas development around an OGDP Location, the number of existing Oil and Gas Locations within one mile of each OGDP Location are reported in CIDER. The Front Range has the most Oil and Gas Locations within one mile of approved OGDP Locations (Figures 59 and 60).

Figure 59: Number of Existing Oil and Gas Locations Within 1 Mile of OGDP Location

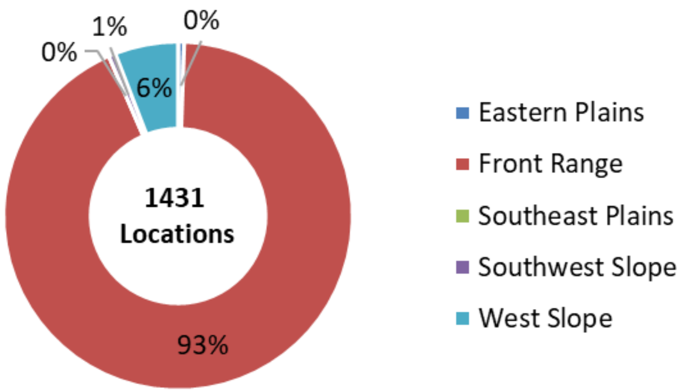
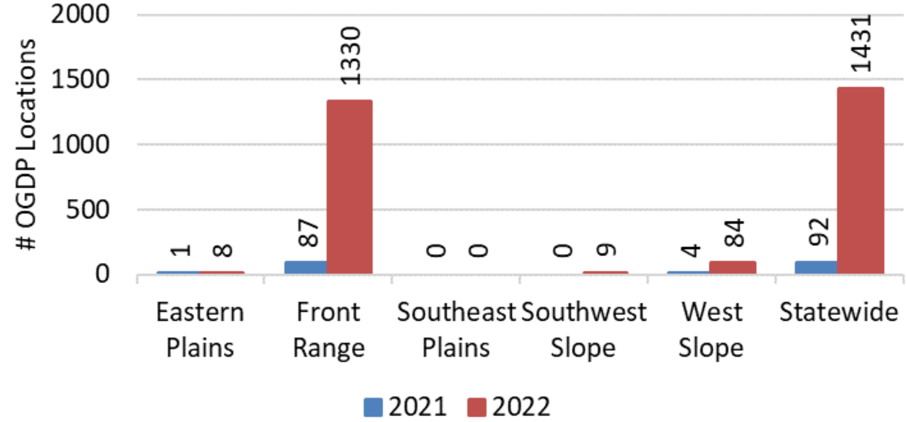


Figure 60: Number of Existing Oil and Gas Locations Within 1 Mile of OGDP Locations



Wildlife

2022 saw the first locations approved within a High Priority Habitat (HPH) under the new rules. Siting of new or amended Locations within HPH automatically requires a consultation with CPW; in all cases both the operator and Staff consulted with CPW, either in a pre-application consultation, during technical review, or most commonly, both before and during the permitting process. Through these consultations, CPW and COGCC Staff work with applicants to avoid impacts, either spatially or temporally, and if impacts cannot be avoided, additional best management practices (BMPs) are agreed upon and/or conditions of approval (COAs) are applied to the permit to minimize impacts. Where residual adverse impacts to wildlife remain after avoidance and minimization efforts, offset measures are implemented, such as compensatory mitigation fees (see Compensatory Mitigation section below). Of the 77 approved OGDP Locations, 24 (31%) are greater than one mile from any HPH, 31 (40%) are within one mile of an HPH, and 22 (29%) are within an HPH (Figure 61); Figure 62 below shows this breakout by operating area. All of the information within this Wildlife section provided as an average does so only for locations within an HPH; CIDER data for locations not within an HPH are included in the land use section above, and are left out of the averages in this Wildlife section.

Figure 61: OGDP Location Relation to HPH

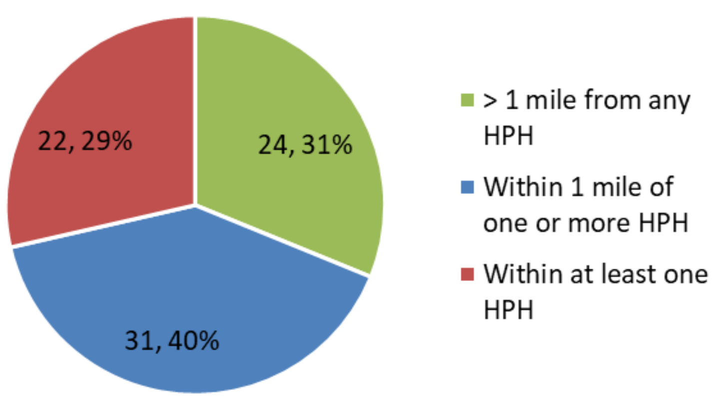
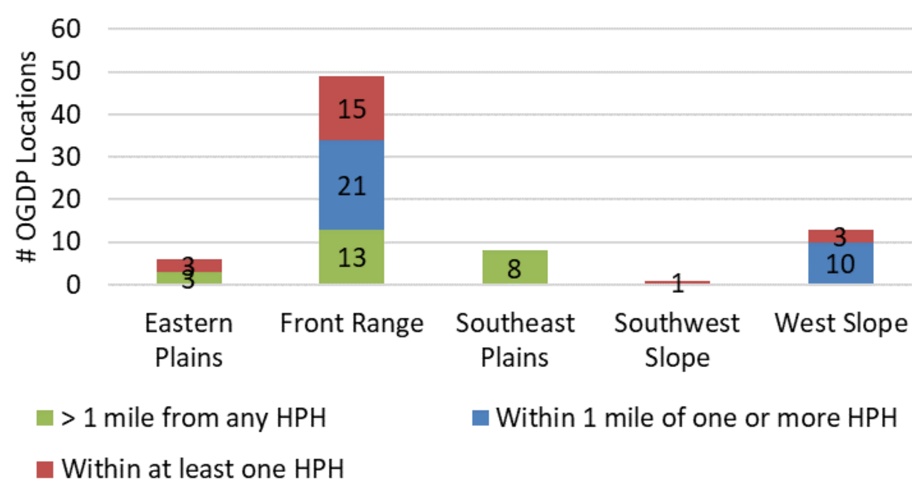


Figure 62: Location Relation to HPH



Distance to High Priority Habitat

When locations are within one mile of an HPH, the majority are between 2001-5280 feet of the HPH (Figure 63). The average distance to an HPH is similar across operating areas, with a statewide average of 2,663 feet, for OGDPs approved in 2022 (Figure 64); OGDP Locations greater than one mile away or within an HPH are excluded from this average.

Figure 63: Distribution of Distance to HPH When Within 1 Mile

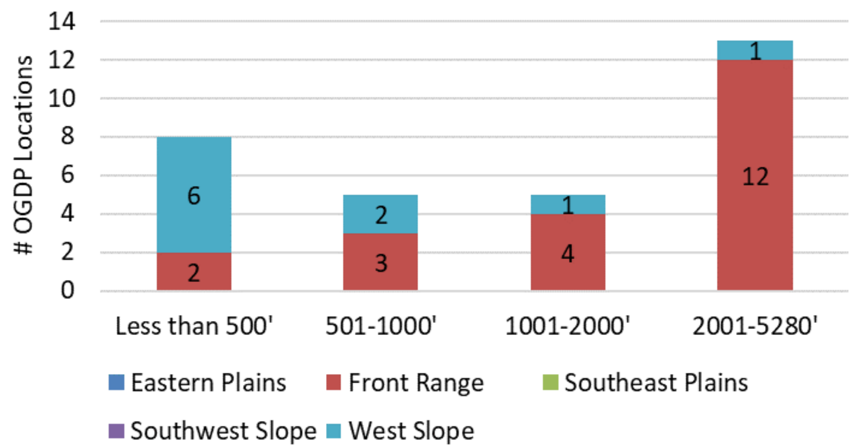
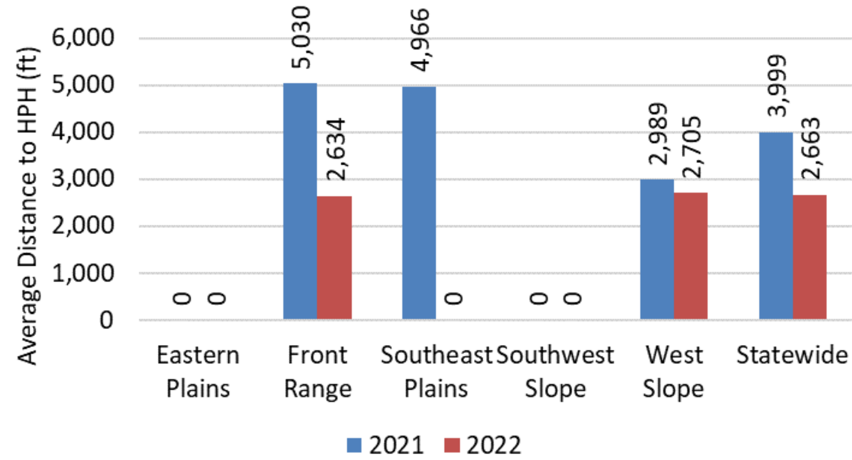


Figure 64: Average Distance to HPH When Within 1 Mile



Disturbance Within High Priority Habitat

Information in this section is reported in three ways: total surface disturbance, OGDP Location disturbance, and access road, pipeline corridor, and utility corridor disturbance. The total surface disturbances are the sum of the OGDP Location disturbance area and the access road, pipeline corridor, and utility corridor disturbance. These disturbances represent direct impacts to the species; CPW conducts additional analysis of certain indirect impacts, which are not included in CIDER. The access road, pipeline corridor, and utility corridor disturbances are collected at the OGDP Level to reflect their shared use within all locations at the OGDP. Therefore, total surface disturbances are only averaged per well, OGDP Location surface disturbances are also averaged per OGDP Location, and access road, pipeline corridor, and utility corridor disturbances are also averaged per OGDP.

Figure 65: Percent of Total Construction Disturbance within an HPH by Operating Area

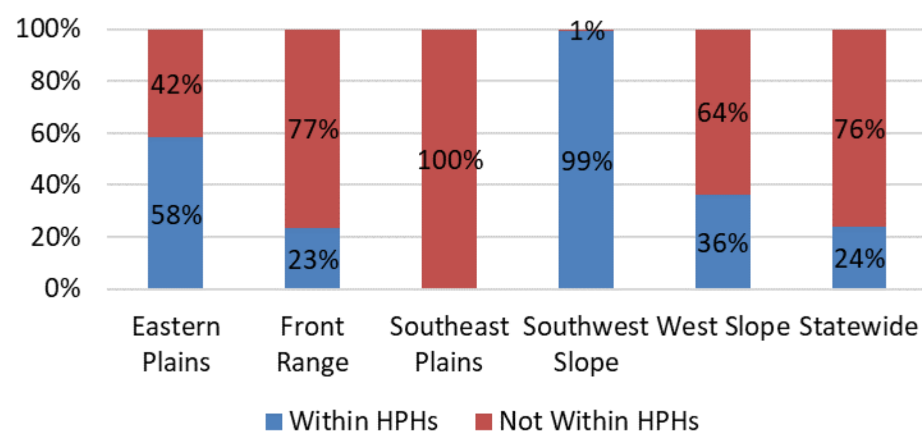


Figure 66: Total Construction Disturbance Within an HPH

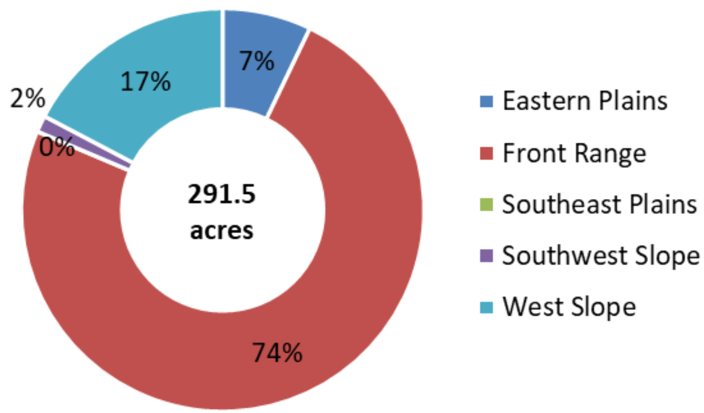
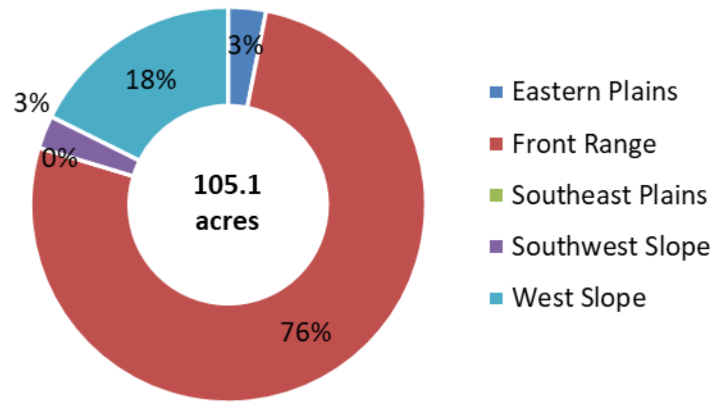
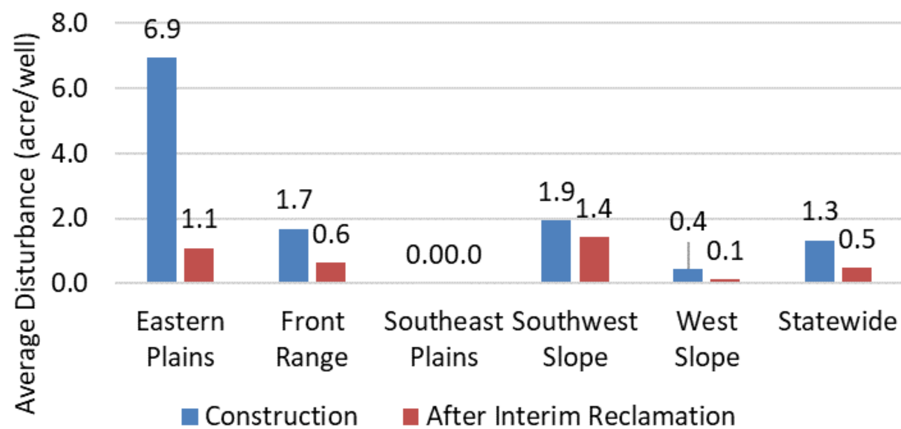


Figure 67: Total Disturbance After Interim Reclamation Within an HPH



Total construction surface disturbance within an HPH is 291.5 acres (Figure 66), which was approximately 24% of the 1,215.8 acre total surface construction disturbance for OGDPs approved in 2022 as shown in Figure 65 along with the portion of total surface construction disturbance within in HPH by operating area. The post-interim reclamation disturbance within an HPH for OGDPs approved in 2022 is 103.8 acres (Figure 67). The average total construction surface disturbance within an HPH per well is greatest in the Eastern Plains, however, the average total post-interim reclamation disturbance within an HPH per well is greatest on the Southwest Slope (Figure 68).

Figure 68: Average Total Surface Disturbance in HPH per Well



The OGDP Location disturbances within an HPH is 196.8 acres (Figure 70), which is approximately 24% of the 816.5 acre OGDP Location surface construction disturbance for OGDPs approved in 2022 as shown in Figure 69 along with the portion of OGDP Location construction disturbance within HPH by operating area. OGDP Location post-interim reclamation disturbance within an HPH for OGDPs approved in 2022 is 77.9 acres, (Figure 71). Only 8% of the OGDP Location surface disturbance within an HPH is on federal land (Figure 72), which is all on the West Slope, and the rest is located on privately owned surface (Figure 73)[8].

Figure 69: Percent of OGDP Location Construction Disturbance within an HPH by Operating Area

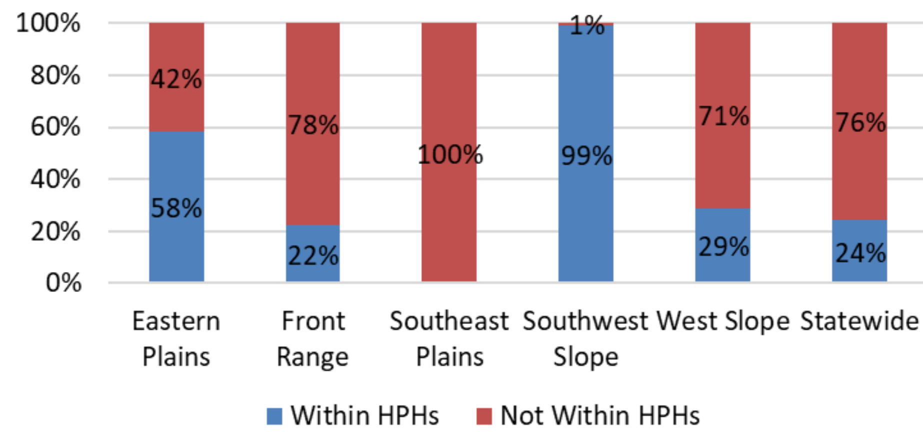


Figure 70: OGDP Location Construction Disturbance Within an HPH

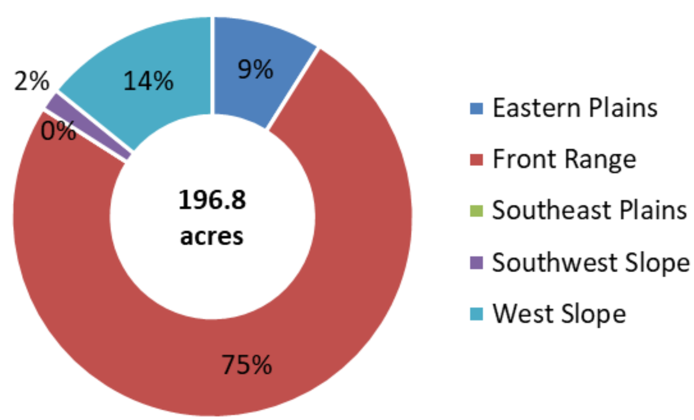
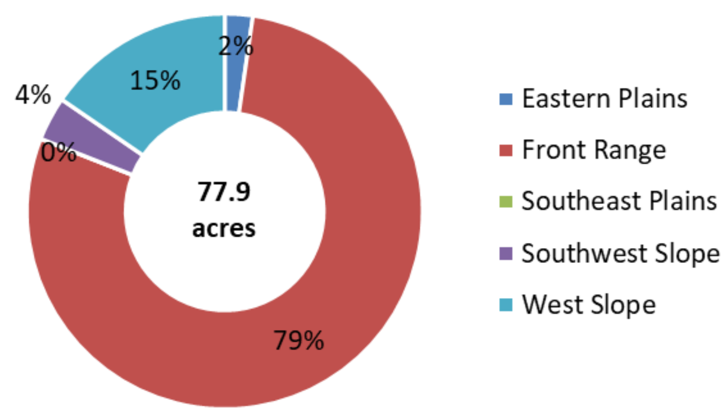


Figure 71: ODGP Location Disturbance After Interim Reclamation Within an HPH



[8] Because the surface owner type is reported by location on the Form 2A, it was only included for OGDP Location surface disturbances. While the surface owner type for OGDPs approved in 2022 does not differ by location within an OGDP, which would allow the application of this field to the access road, pipeline corridor, and utility corridor disturbance, the same cannot be guaranteed for future OGDPs.

Figure 72: Construction Disturbance Within HPH Surface Ownership Type

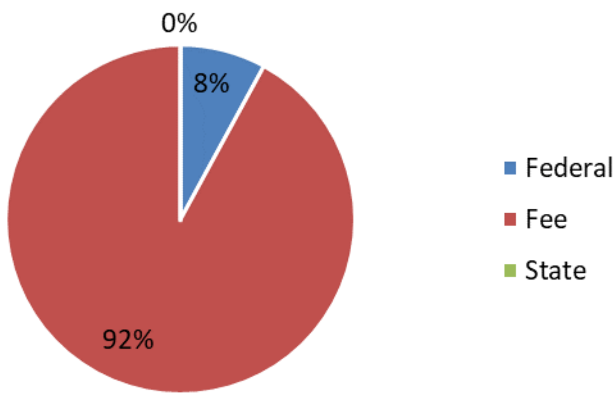
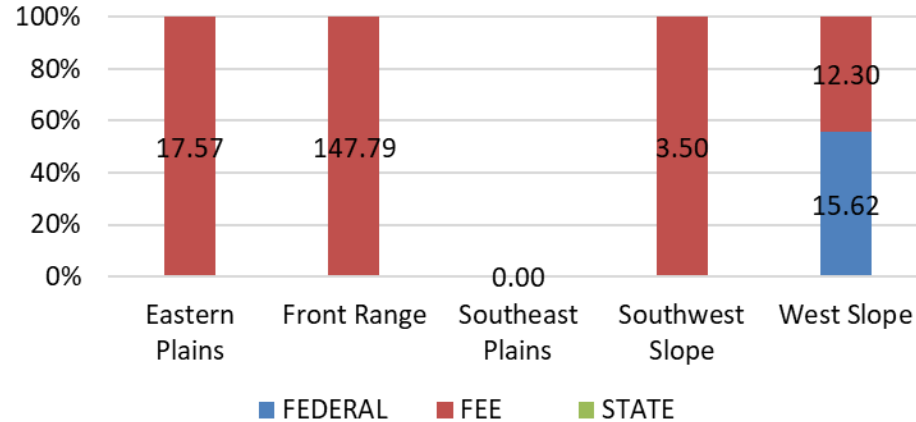


Figure 73: OGDP Location Construction Disturbance Within HPH by Surface Ownership Type (acre)



The average ODGP Location disturbance in an HPH is greatest in the West Slope for both construction and post-interim reclamation (Figure 74). The average OGDP Location disturbance per well in an HPH during the construction phase is greatest in the Eastern Plains (Figure 75). This is likely due to the Eastern Plains Locations being predominantly single well Locations; the space needed to bring a rig in for one well is disproportionately larger for a single well pad than it is for a multi-well pad, such as in the Front Range or West Slope. Once the single well is put into production, the production surface can be reclaimed down much more than a pad with multiple wells. The average per well post-interim reclamation disturbance is greatest in the Southwest Slope, which similar to the Eastern Plains, is from a single location with only two wells. Additionally, the type of operations at the single OGDP Location approved in the Southwest Slope are unique to this part of the state, whereby multiple sidetrack laterals are permitted from each wellhead, effectively increasing the scope of mineral development from fewer wellheads. More information from future OGDPs in this area will be necessary to understand whether this is the average to be expected or an outlier.

Figure 74: Average OGDP Location Surface Disturbance in HPH per Location

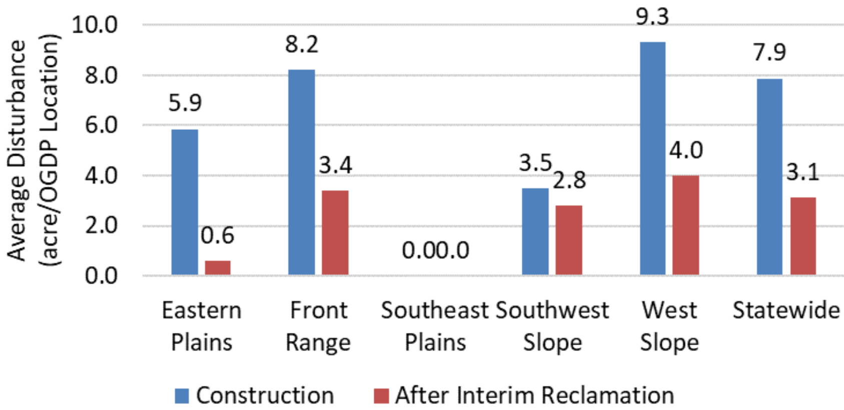
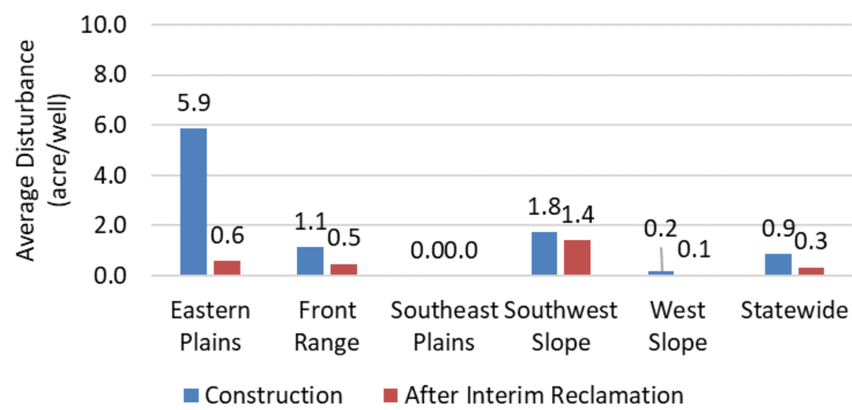


Figure 75: Average ODGP Location Surface Disturbance in HPH per Well



The access road, pipeline corridor, and utility corridor disturbance within an HPH is 94.8 acres (Figure 77), which is approximately 24% of the 399.4 acre access road, pipeline corridor, and utility corridor construction disturbance for OGDPs approved in 2022 as shown in Figure 76 along with the portion of access road, pipeline corridor, and utility corridor disturbance with HPH by operating area. The access road, pipeline corridor, and utility corridor post-interim reclamation disturbance within an HPH for OGDPs approved in 2022 is 25.9 acres (Figure 78). The average access road, pipeline corridor, and utility corridor disturbance in an HPH per OGDP is greatest in the Front Range for both construction and post-interim reclamation (Figure 79). However, this access road, pipeline corridor, and utility corridor disturbance is greatest in the Eastern Plains when averaged by well (Figure 80).

Figure 76: Percent of Road/Pipeline/Utility Construction Disturbance within an HPH by Operating Area

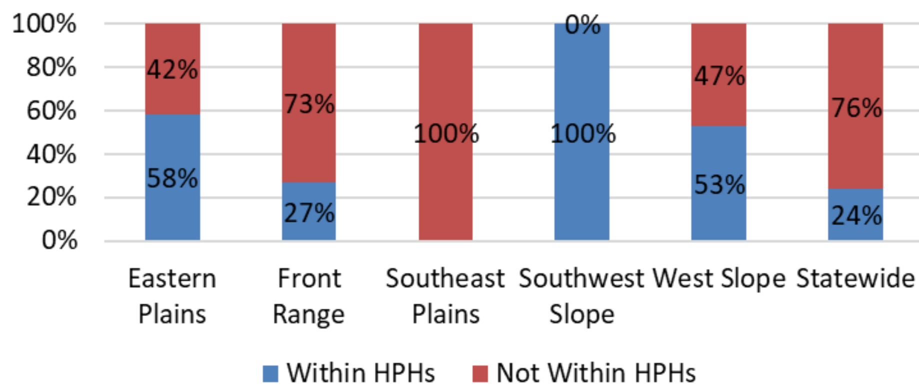


Figure 77: Road/Pipeline/Utility Construction Disturbance Within an HPH

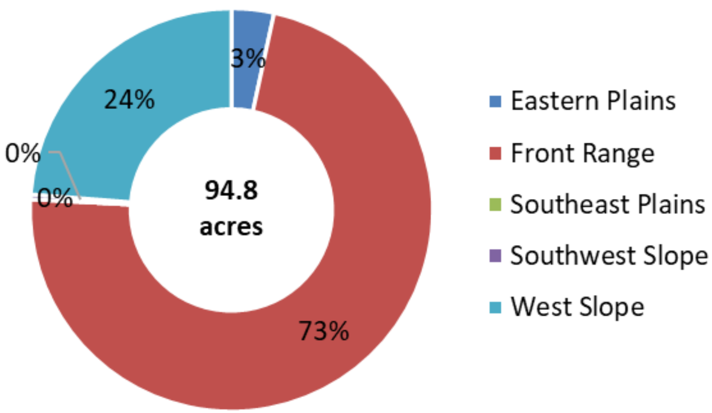


Figure 78: Road/Pipeline/Utility Disturbance After Interim Reclamation Within an HPH

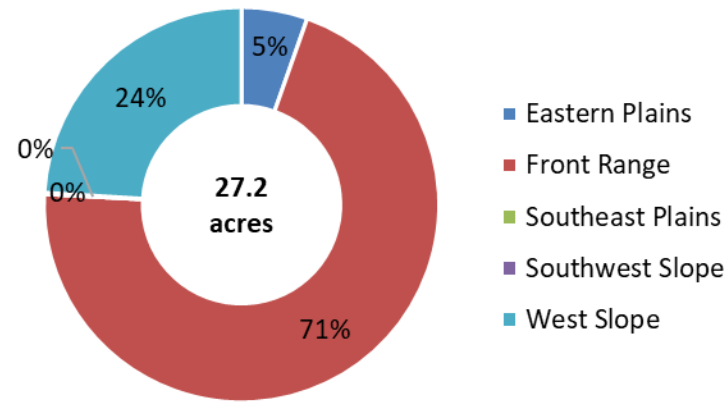


Figure 79: Average Road/Pipeline/Utility Surface Disturbance in HPH per OGDP

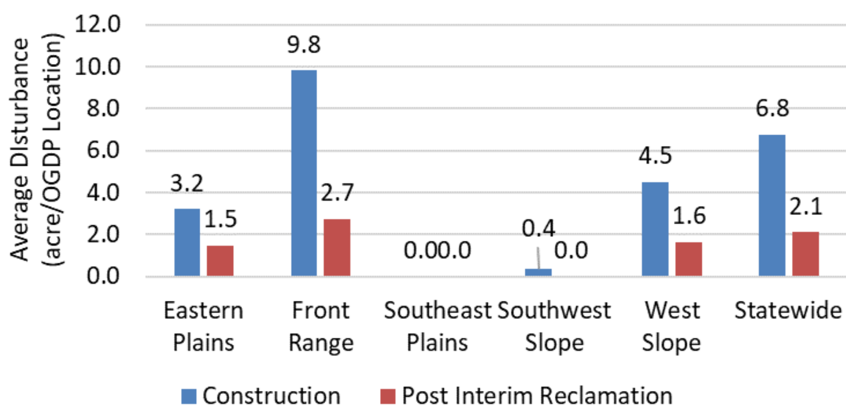
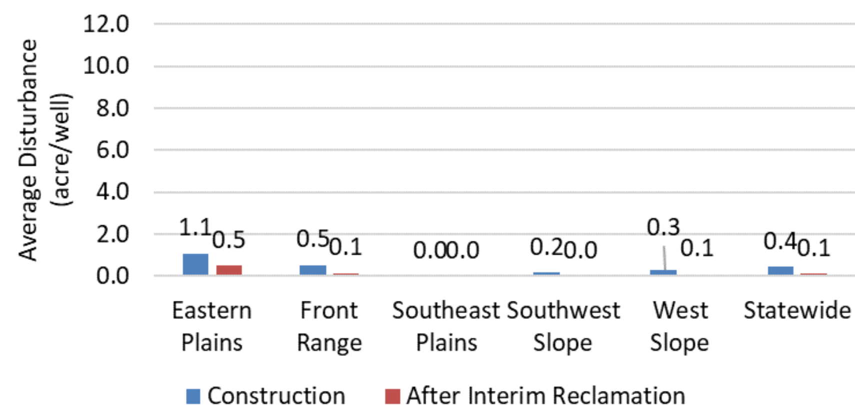


Figure 80: Average Road/Pipeline/Utility Surface Disturbance in HPH per Well



To understand the type of habitat most impacted, the construction disturbances within each HPH were charted both by rule category and by HPH. Because one ODGP Location may be located within more than one HPH, the OGDP Location's associated surface disturbance may be counted in more than one of the rule categories and/or HPHs in the following figures. When these locations are within one or more HPH, CIDER only collects the total disturbance for each HPH, which represents construction disturbance within the HPH; therefore, the following charts are only available for construction disturbances. The long term impact to the HPH can be better understood if additional detail was to be provided on the Form 2B about disturbances within each HPH post-interim reclamation.

The HPH with the greatest total surface disturbance (OGDP Location plus access road, pipeline corridor, and utility corridor) is the Pronghorn Winter Concentration Area (Rule 1202.d.(4)). Big game high priority habitats are expected to receive higher levels of overall disturbance due to their larger footprint on the landscape in Colorado, and their overlap with active oil and gas basins. Additionally, these habitats fall under the Rule 1202.d. category which allows disturbance while including considerations for facility density and compensatory mitigation to offset the unavoidable adverse impacts. Disturbance by rule category and species/HPH are shown in Figures 81-84[9] below.

It is important to note that although Rule 1202.c. is generally recognized as "no surface occupancy", there are regulatory off-ramps that allow construction within some of these habitats, particularly in certain aquatic habitats. These off-ramps require a waiver from CPW (following consultation and application of best management practices), an exception from the Director, and approval by the Commission.

[9] The two Rule 1202.c habitats shown in Figure 83 are examples of overlapping HPHs, so the total in Figure 81 is less than the sum of Figure 83. Similarly in Figure 84, many of the 1202.d HPHs overlap, so the totals shown in Figure 84 are greater than that counted in Figure 81 for Rule 1202.d disturbance.

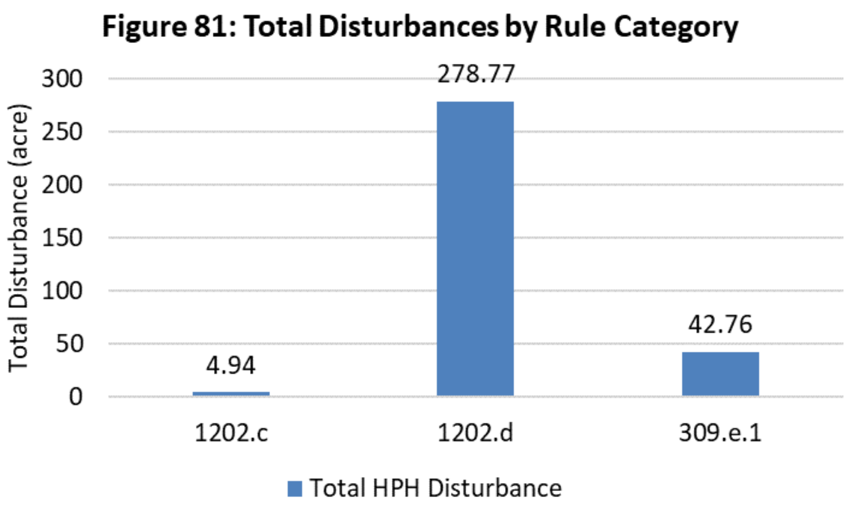


Figure 81: Total Disturbances by Rule Category
Total Disturbance (acre)
300
250
200
150
100
50
0
278.77
4.94
42.76
1202.c
1202.d
309.e.1
Total HPH Disturbance

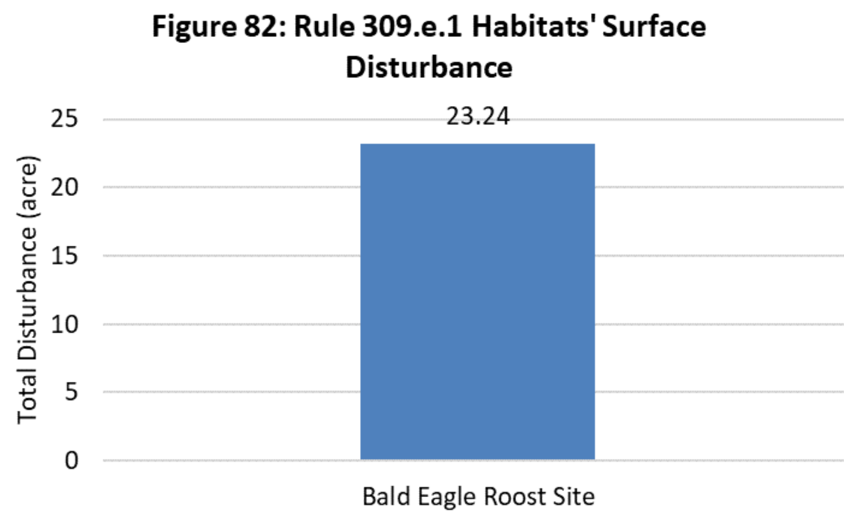


Figure 82: Rule 309.e.1 Habitats' Surface Disturbance
Total Disturbance (acre)
25
20
15
10
5
0
23.24
Bald Eagle Roost Site

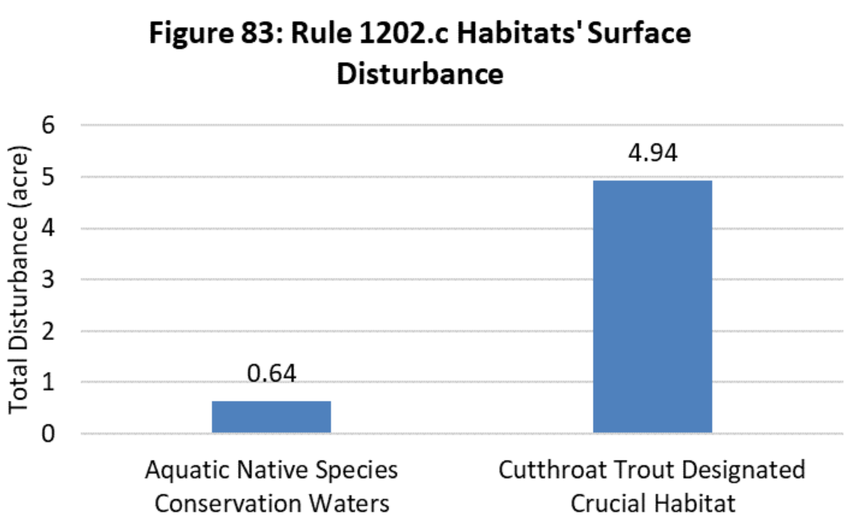


Figure 83: Rule 1202.c Habitats' Surface Disturbance
Total Disturbance (acre)
6
5
4
3
2
1
0
0.64
4.94
Aquatic Native Species Conservation Waters
Cutthroat Trout Designated Crucial Habitat

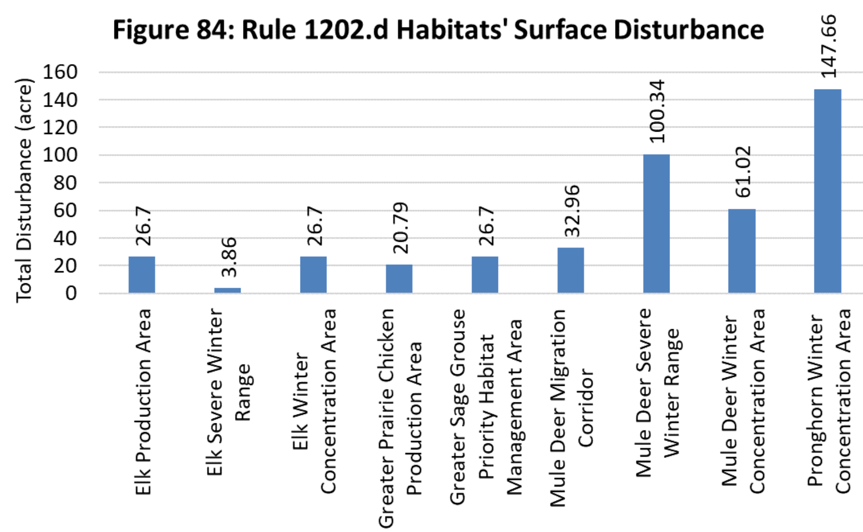


Figure 84: Rule 1202.d Habitats' Surface Disturbance
Total Disturbance (acre)
160
140
120
100
80
60
40
20
0
26.7
3.86
26.7
20.79
26.7
32.96
100.34
61.02
147.66
Elk Production Area
Elk Severe Winter Range
Elk Winter Concentration Area
Greater Prairie Chicken Production Area
Greater Sage Grouse Priority Habitat Management Area
Mule Deer Migration Corridor
Mule Deer Severe Winter Range
Mule Deer Winter Concentration Area
Pronghorn Winter Concentration Area

Compensatory Mitigation

For OGDP Locations approved in 2022, direct and indirect compensatory mitigation are required for 20 and 9 OGDP Locations, respectively (Table 1 and Table 2). A single OGDP Location may require both direct and indirect compensatory mitigation, so the total number of OGDP Locations requiring compensatory mitigation will not equal the sum of direct and indirect mitigation. Indeed, the nine OGDP Locations approved in 2022 that require indirect compensatory mitigation also require direct compensatory mitigation.

Table 1: Locations where Compensatory Mitigation is Required by Operating Area

Operating Area	Direct Compensatory Mitigation Required	Indirect Compensatory Mitigation Required	Total Compensatory Mitigation Required
Eastern Plains	3	1	3
Front Range	14	5	14
Southeast Plains	0	0	0
Southwest Slope	1	1	1
West Slope	2	2	2
Statewide	**20**	**9**	**20**

Table 2: Locations where Compensatory Mitigation is Required by County

County	Direct Compensatory Mitigation Required	Indirect Compensatory Mitigation Required	Total Compensatory Mitigation Required
La Plata	1	1	1
Rio Blanco	2	2	2
Washington	3	1	3
Weld	14	5	14
Statewide	**20**	**9**	**20**

Operators opted to pay compensatory mitigation fees for eighteen of the twenty OGDP Locations where compensatory mitigation is required. CPW has collected $357,312.90 of the $840,358.39 in fees associated with OGDP Locations approved in 2022 (Table 3 and Table 4)[10]. The remaining fees will be collected at least 30 days prior to the submission of the Form 42 Construction Notification. None of these fees have been spent as of December 31, 2022 due to the time needed to plan and implement habitat enhancement and/or conservation projects after CPW receives the funds. CPW is currently working on regional planning and prioritization processes to identify upcoming projects and opportunities. Potential projects will include a mix of near-term actionable habitat enhancement projects (e.g., pinyon/juniper mastication, noxious weed treatments, fence removals, wetland restorations, etc.), and larger long-term habitat conservation projects (e.g., conservation easements, fee/title land acquisitions, highway crossing infrastructure, etc.). To the extent possible, these projects will be commensurate with the impacts identified in this, and future cumulative impact reports (i.e., same species, habitats, landscapes, scale, etc.). CPW plans to provide a standalone compensatory mitigation report in future years containing details for projects that have been implemented during that calendar year. These projects may be completed with funds received in any year prior to their implementation.

Table 3: Compensatory Mitigation Fees by Operating Area

Operating Area	Direct Compensatory Mitigation Fees		Indirect Compensatory Mitigation Fees		Total Compensatory Mitigation Fees	
	Total	Average Per Location	Total	Average Per Location	Total	Average Per Location
Eastern Plains	$41,250.00	$13,750.00	$45,570.00	$45,570.00	$86,820.00	$28,940.00
Front Range	$354,361.90	$27,258.61	$124,961.49	$24,992.30	$479,323.39	$36,871.03
Southeast Plains	$0.00	N/A	$0.00	N/A	$0.00	N/A
Southwest Slope	$13,750.00	$13,750.00	$243,285.00	$243,285.00	$257,035.00	$257,035.00
West Slope	$13,750.00	$13,750.00	$3,430.00	$3,430.00	$17,180.00	$17,180.00
Statewide	**$423,111.90**	**$23,506.22**	**$417,246.49**	**$52,155.81**	**$840,358.39**	**$46,686.58**

[10] Per Location averages in Table 3 and Table 4 are averaged for locations where fees apply (i.e. locations with no fee were not included in this average).

Table 4: Compensatory Mitigation Fees by County

County	Direct Compensatory Mitigation Fees		Indirect Compensatory Mitigation Fees		Total Compensatory Mitigation Fees	
	Total	Average Per Location	Total	Average Per Location	Total	Average Per Location
La Plata	$13,750.00	$13,750.00	$243,285.00	$243,285.00	$257,035.00	$257,035.00
Rio Blanco	$13,750.00	$13,750.00	$3,430.00	$3,430.00	$17,180.00	$17,180.00
Washington	$41,250.00	$13,750.00	$45,570.00	$45,570.00	$86,820.00	$28,940.00
Weld	$354,361.90	$27,258.61	$124,961.49	$20,826.92	$479,323.39	$29,957.71
Statewide	**$423,111.90**	**$23,506.22**	**$417,246.49**	**$52,155.81**	**$840,358.39**	**$46,686.58**

Of the two OGDP Locations where no mitigation fees will be collected, one was waived due to changes in CPW's HPH map layers (removal of HPH in the area of development) that had not yet been adopted by the COGCC Commission through rulemaking, and at the other the operator elected to complete their own compensatory mitigation project pursuant to Rule 1203.a.(1). This project was completed in 2022 by Caerus Piceance, LLC to offset the adverse direct and indirect impacts for the ELU A18-495 Pad (Location ID: 483521). The completed project was a vegetation treatment intended to enhance and expand existing habitat for greater sage-grouse. The project consisted of mechanically treating (mastication with hydroaxe) 218 acres of mature mountain shrub and gamble oak within greater sage-grouse priority habitat management area (PHMA) HPH on private lands. This project occurred within Garfield County, Colorado. The photo presented here as Figure 85 shows the regeneration of native forbs and sagebrush that are important for greater sage-grouse and other sagebrush-dependent species of wildlife. Full details for this project can be found within the operator's Compensatory Mitigation Plan document.

Figure 85: Caerus Compensatory Mitigation Project Treatment

Air Quality

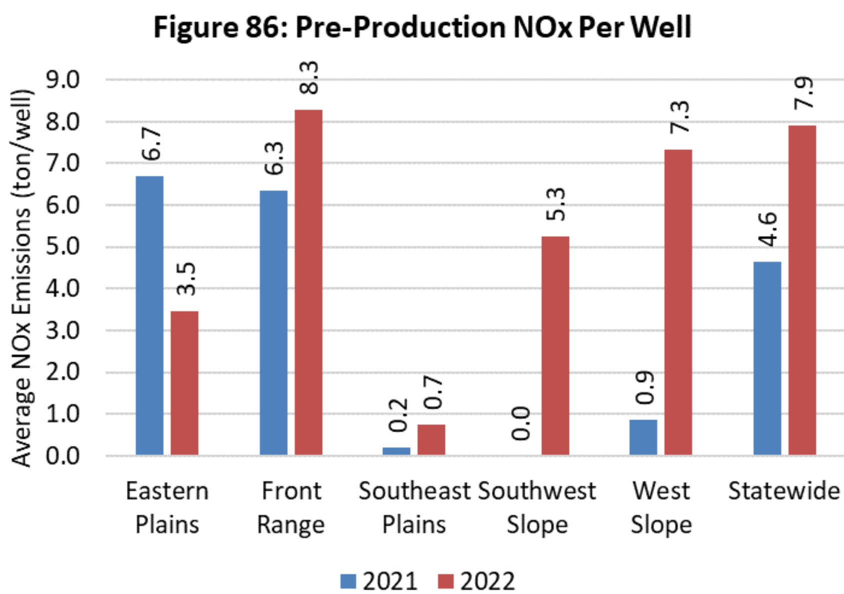
Emissions estimates are provided based on anticipated pre-production and production conditions[11]. The actual emissions will be reported in the APCD Oil and Gas Emissions Inventory Annual Reporting program (ONGAEIR) for the oil and gas industry (Regulation Number 7, Part D, Section V) for both Pre-Production and Production operations, and a discussion about this information is included in the 904.a.(3) APCD Oil and Gas Emissions Inventory section of this report. In the figures below, Pre-Production operations include the construction, drilling, and completion phases, while Production emissions are estimated for the first full year that all wells are producing.

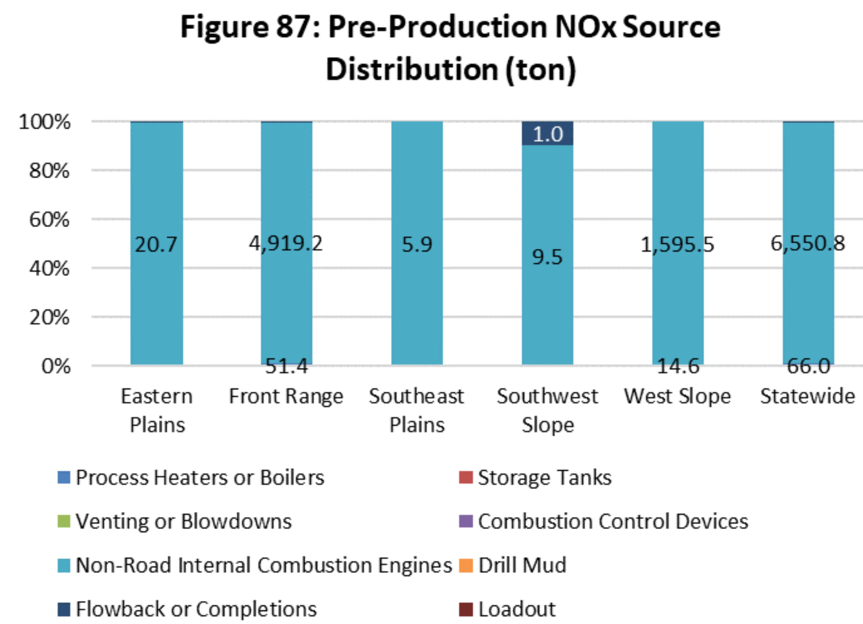
This report summarizes emissions estimates, as averaged on a per well basis, for nitrogen oxides (NOx), volatile organic compounds (VOC), methane (CH_4), and total hazardous air pollutants (HAPs). The contribution of each source type reported in CIDER to the total estimated emissions estimates of OGDP Locations approved in 2022 is broken out and represented as a distribution chart showing the relative contributions of each source category[12]. The CIDER data contributing to the information discussed below are based on estimates made by the operator at the time of the OGDP application submittal. Since some of these OGDPs have been submitted, new Air Quality Control Commission (AQCC) regulations may have been adopted that would require additional control measures at these locations, resulting in actual emissions as contained in a future permit application and/or reported to ONGAEIR that may be lower than the estimates provided to CIDER.

The evaluation of emissions estimates as shown below was conducted with the information contained in CIDER, which is limited to total emissions estimates per OGDP Location, and was designed to be comparable to ONGAEIR pollutants and categories. ONGAEIR, as well as subsequent APCD permit applications, will contain additional information that may further help explain the emissions from these locations. In 2022, the APCD began looking closer at the estimated emissions being provided by operators during their consultations with the COGCC related to CAPs. APCD reviewed with operators specific inputs, calculation methodologies, and assumptions that went into these calculations. For example, the air permit applications submitted to APCD and actual emissions reported to ONGAEIR may utilize site-specific or representative samples. Without this tailored information, some operators may be utilizing state default emission factors, which may be higher than the actual emissions once a site specific factor is applied, resulting in the potential for CIDER emission estimates to be higher than emissions limits later provided in APCD permit applications. The APCD and operators are working to ensure estimated emissions are as close to actual as is possible at the OGDP stage of the development process. Subsequently, the APCD expanded these discussions to include the estimated emissions on the Form 2Bs. Although discussions are still underway, these efforts are expected to improve the accuracy of CIDER data in future years. COGCC Staff will work closely with the APCD to understand any necessary changes to the Form 2B throughout and as a result of this process. This is in addition to coordination between the COGCC Staff and APCD on any revisions to the Form 2B as a result of future ONGAEIR changes to maintain and improve the ability to compare estimates reported in CIDER to those reported in ONGAEIR.

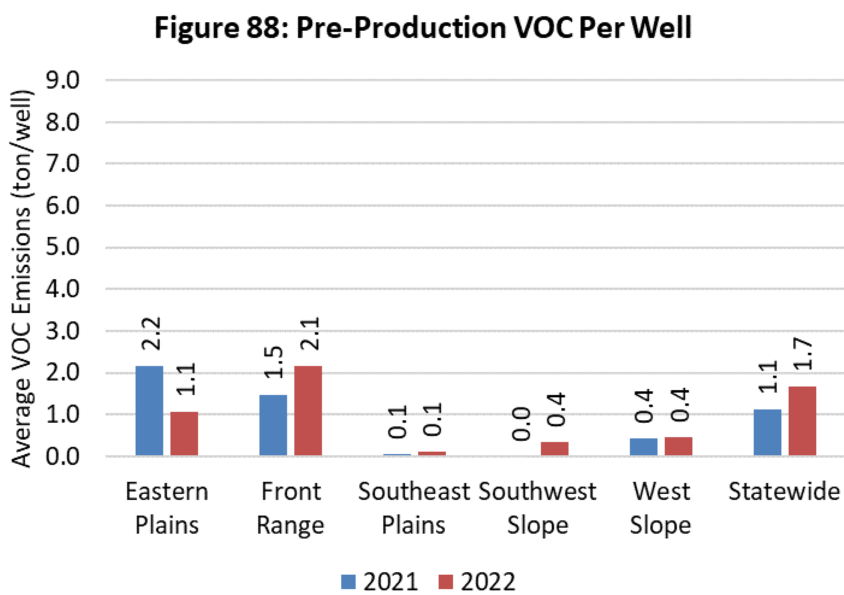
[11] Since the publication of the 2021 Report on the Evaluation of Cumulative Impacts, an operator on the West Slope has provided Staff with updated and more accurate 2021 air quality emission estimates. Therefore, some of the 2021 values in this report have changed since the 2021 report.
[12] For more information on what is included in each source category, please see Appendix A to this report.

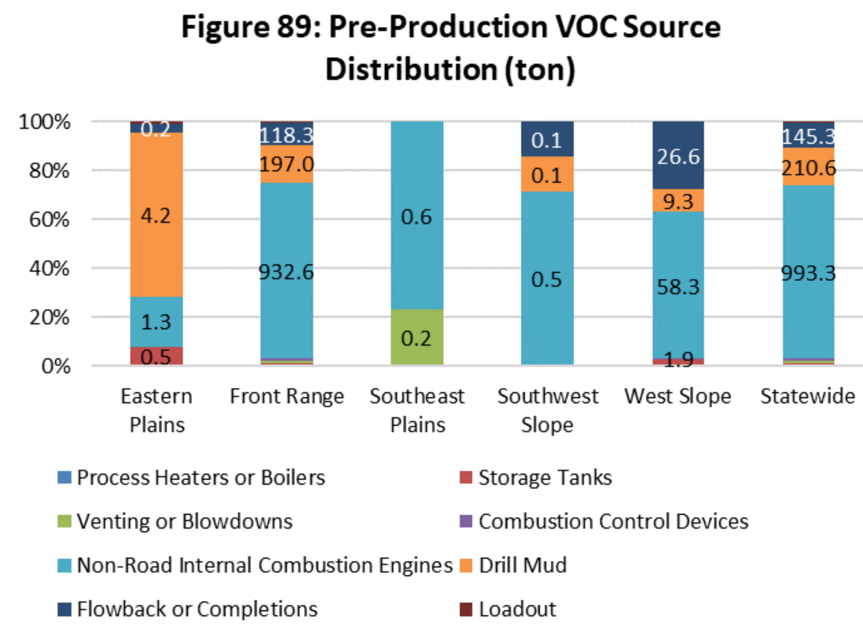
Pre-Production Emissions





The average pre-production NOx emissions estimates per well for OGDPs approved in 2022 is highest for the Front Range (Figure 86). Because NOx is formed as a byproduct of combustion, it is expected that the majority of the NOx emissions will come from combustion source categories, Non-Road Internal Combustion Engines being the primary contributor during pre-production (Figure 87).





The average pre-production VOC emissions estimates per well for OGDPs approved in 2022 is highest for the Front Range (Figure 88). Statewide, the primary contributor to these pre-production VOC Emissions is also Non-Road Internal Combustion Engines, followed by Drill Mud (Figure 89).

The average pre-production methane emissions estimates per well for OGDPs approved in 2022 is highest for the Front Range followed closely by the Eastern Plains (Figure 90). Statewide, the primary contributor to these pre-production methane emissions is Flowback or Completions, followed by Non-Road Internal Combustion Engines, and Loadout (Figure 91).

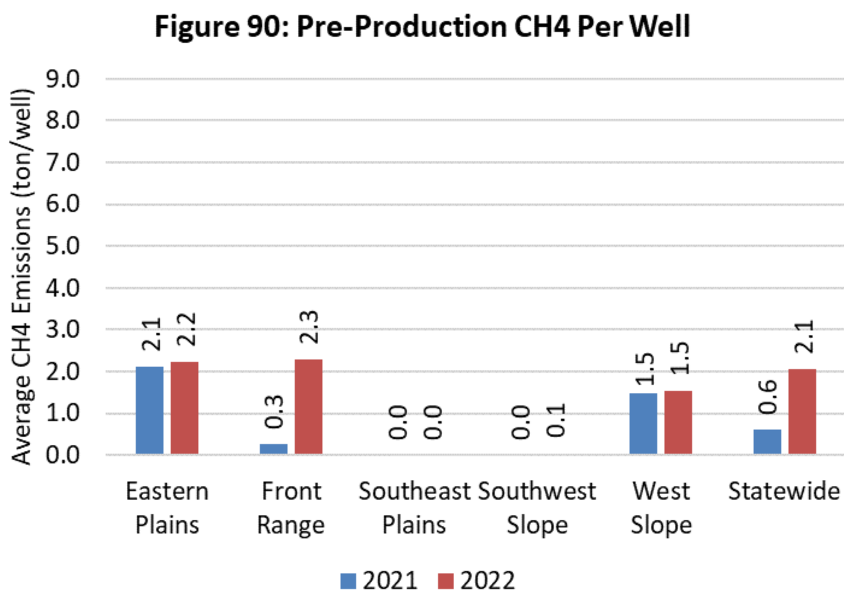


Figure 90: Pre-Production CH4 Per Well
Average CH4 Emissions (ton/well)
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2.1
2.2
0.3
2.3
0.0
0.0
0.0
0.1
1.5
1.5
0.6
2.1
Eastern Plains
Front Range
Southeast Plains
Southwest Slope
West Slope
Statewide
2021
2022

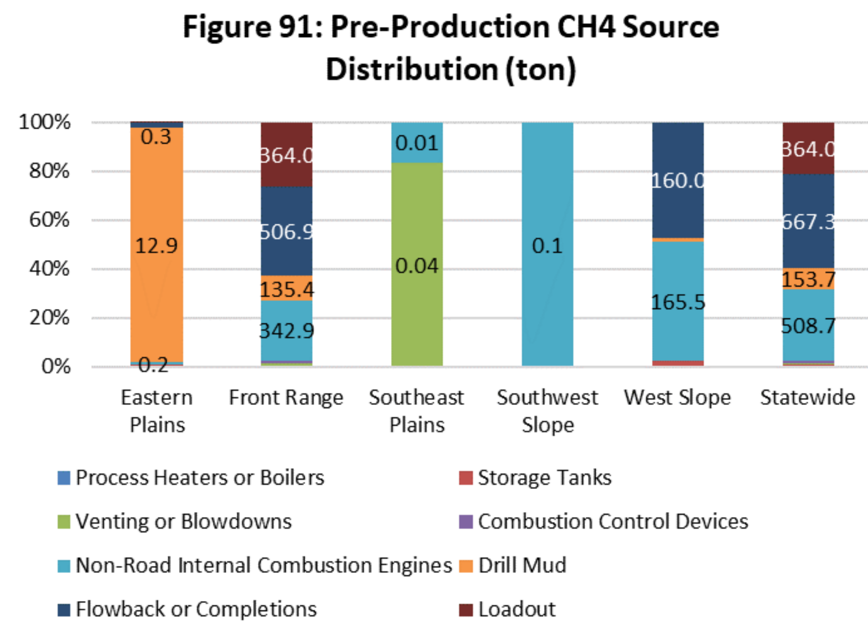


Figure 91: Pre-Production CH4 Source Distribution (ton)
100%
80%
60%
40%
20%
0%
0.3
12.9
0.2
364.0
506.9
135.4
342.9
0.01
0.04
0.1
160.0
165.5
364.0
667.3
153.7
508.7
Eastern Plains
Front Range
Southeast Plains
Southwest Slope
West Slope
Statewide
Process Heaters or Boilers
Storage Tanks
Venting or Blowdowns
Combustion Control Devices
Non-Road Internal Combustion Engines
Drill Mud
Flowback or Completions
Loadout

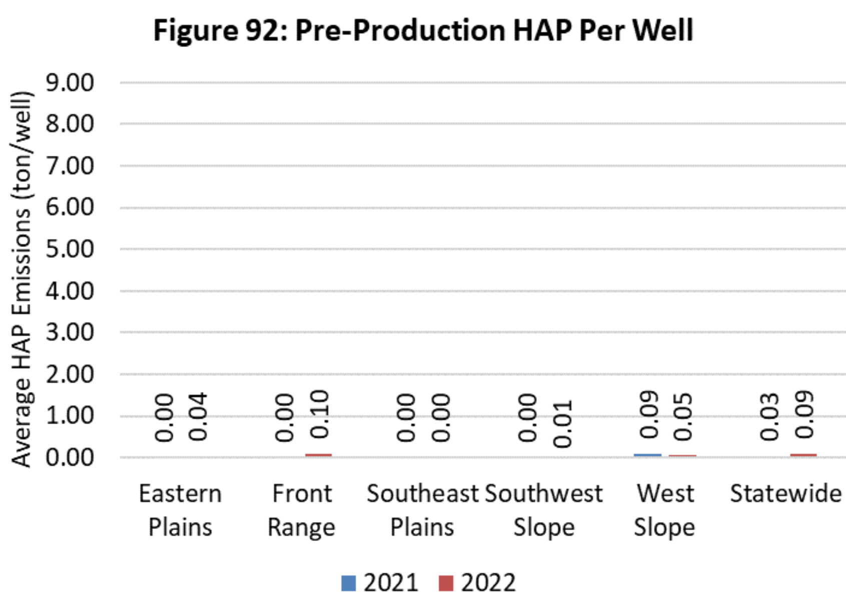


Figure 92: Pre-Production HAP Per Well
Average HAP Emissions (ton/well)
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
0.00
0.04
0.00
0.10
0.00
0.00
0.00
0.01
0.09
0.05
0.03
0.09
Eastern Plains
Front Range
Southeast Plains
Southwest Slope
West Slope
Statewide
2021
2022

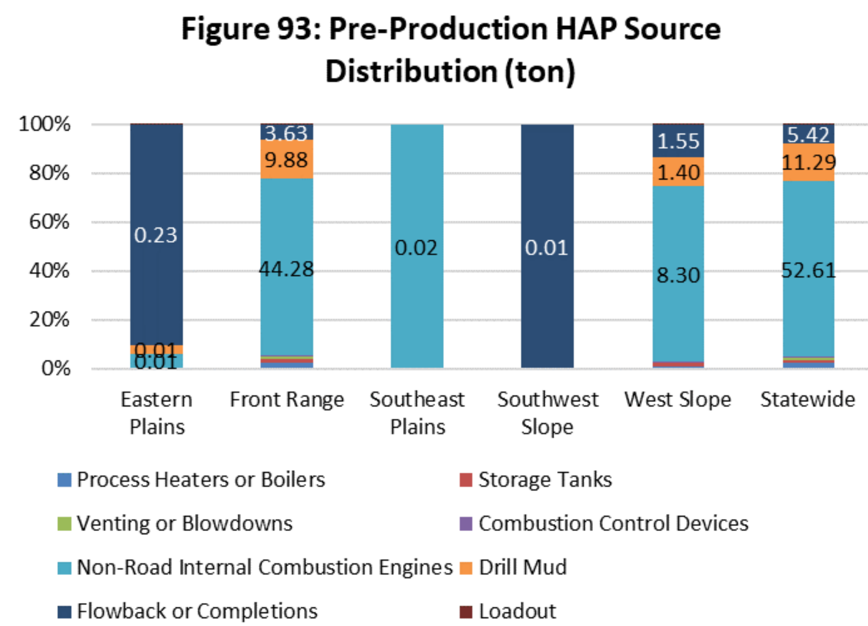


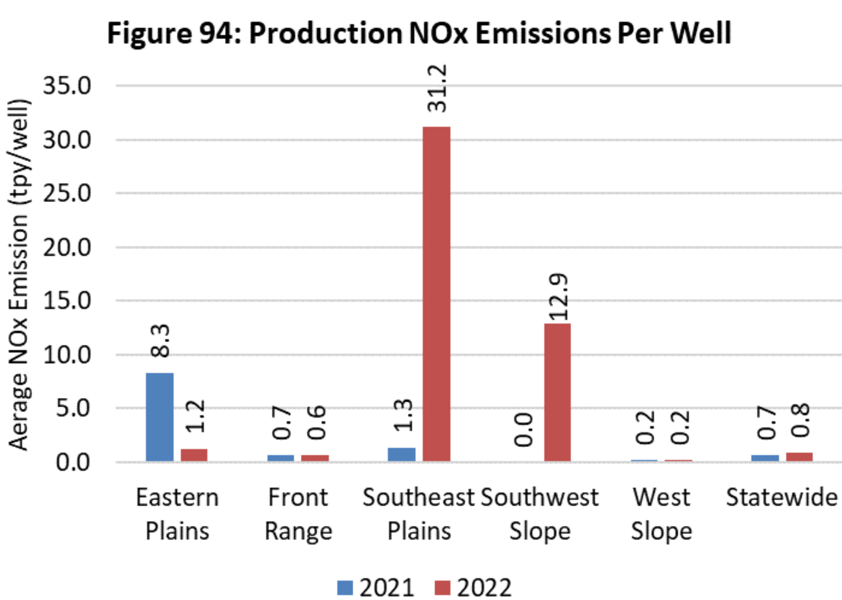
Figure 93: Pre-Production HAP Source Distribution (ton)
100%
80%
60%
40%
20%
0%
0.23
0.01
0.01
3.63
9.88
44.28
0.02
0.01
1.55
1.40
8.30
5.42
11.29
52.61
Eastern Plains
Front Range
Southeast Plains
Southwest Slope
West Slope
Statewide
Process Heaters or Boilers
Storage Tanks
Venting or Blowdowns
Combustion Control Devices
Non-Road Internal Combustion Engines
Drill Mud
Flowback or Completions
Loadout

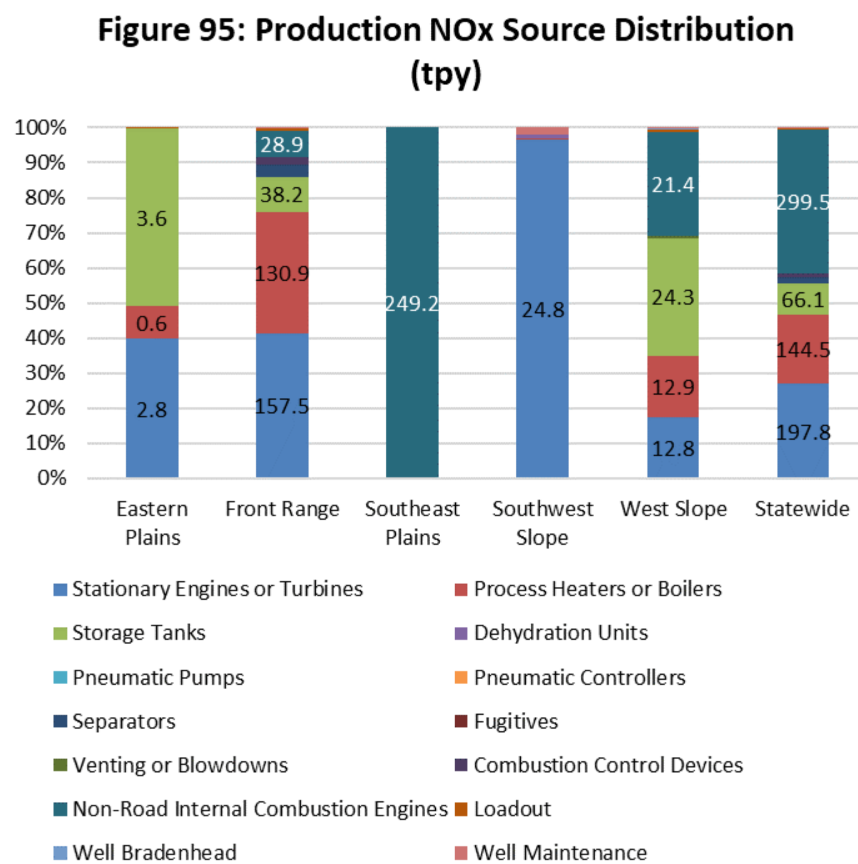
The average pre-production HAP emissions estimates per well for OGDPs approved in 2022 is highest in the Front Range (Figure 92). The primary contribution of Statewide pre-production HAP emissions was Non-Road Internal Combustion Engines; these HAP emissions are primarily made up of formaldehyde created during the combustion process (Figure 93).

The average per well emissions estimates for all pollutants during pre-production are greatest in the Front Range. Wells in the Front Range are typically horizontal wells with long lateral lengths and the equipment required to drill and complete wells in this operating area are different from other operating areas. For example, it may take more horsepower to drill and complete a well in the Front Range than elsewhere in the state, resulting in higher emissions from this area when averaged per well.

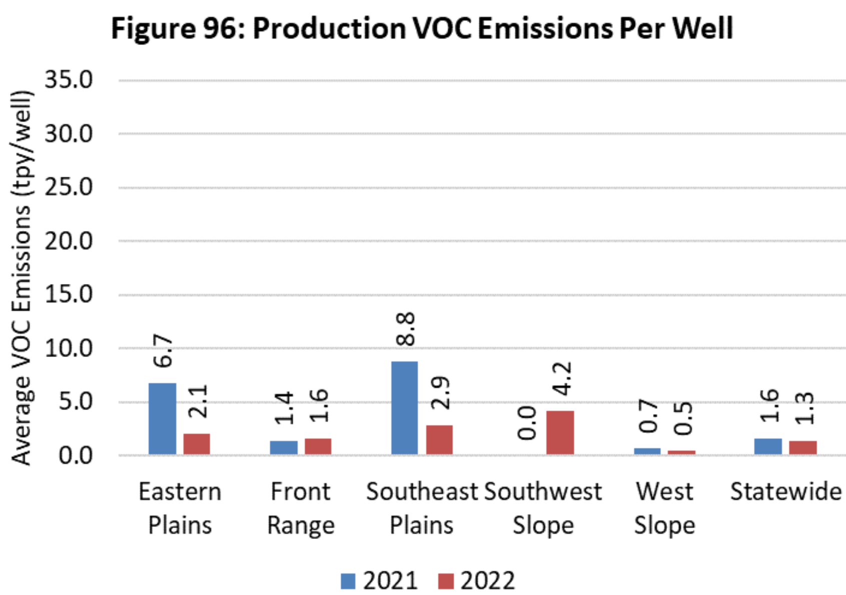
Production Emissions

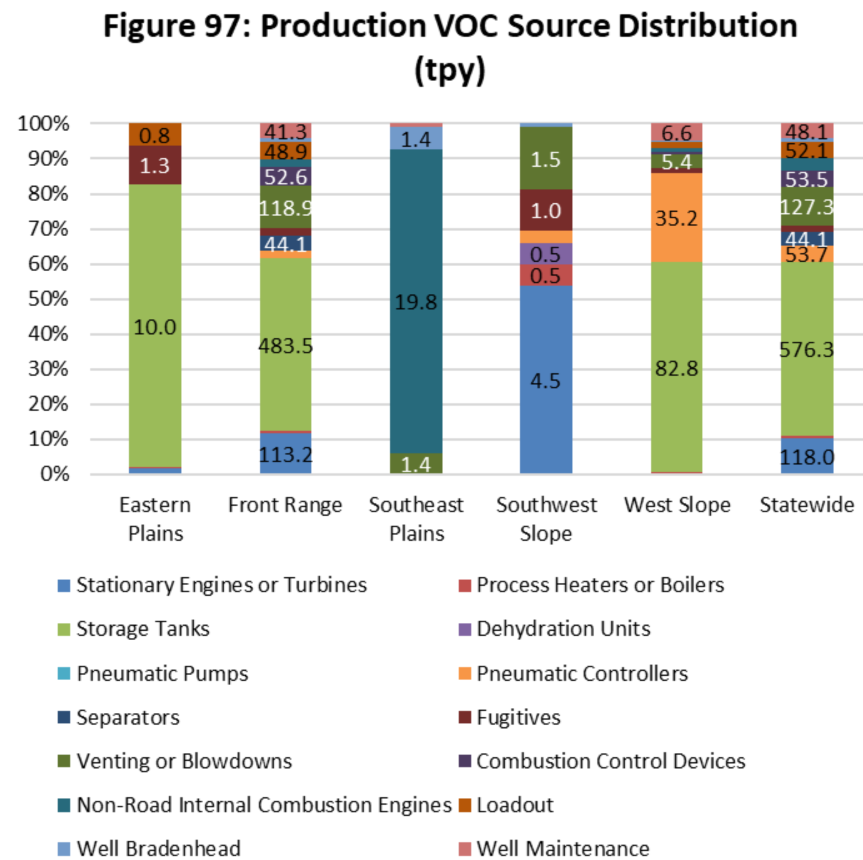
The average production NOx emissions estimates per well for OGDPs approved in 2022 is highest in the Southeast Plains, followed by the Southwest Slope, which has one well and two wells per location, respectively (Figure 94). Two locations in the Southeast Plains are primary contributors to the average for this operating area. These locations both produce helium, which is stored in tanks and then liquefied for truck transport; production NOx emissions come from a temporary diesel fired generator that will operate until the location can switch to electric power. Statewide, production NOx emissions primarily come from Non-Road Internal Combustion Engines, followed by Stationary Engines or Turbines and Process Heaters or Boilers, respectively (Figure 95), which is expected as NOx is a byproduct of combustion. Production NOx emissions from storage tanks are a result of the combustion of emissions from these sources by the emission control devices.



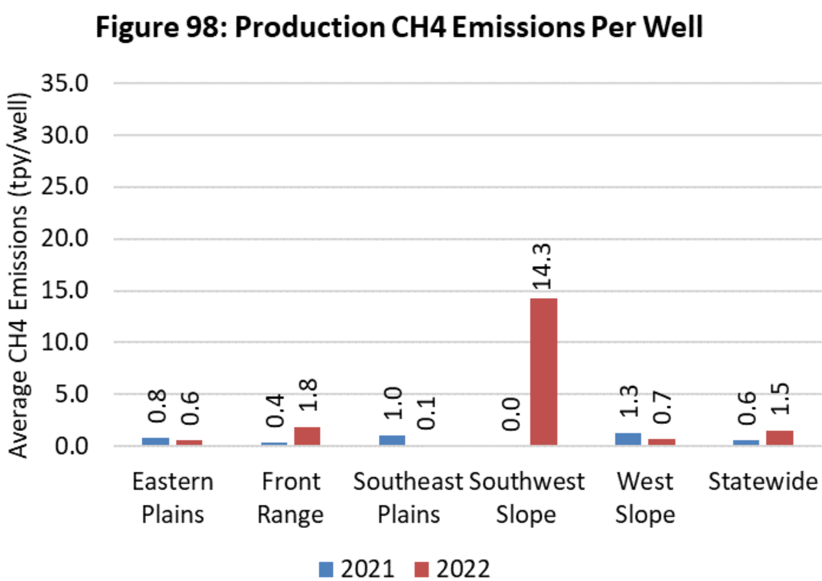


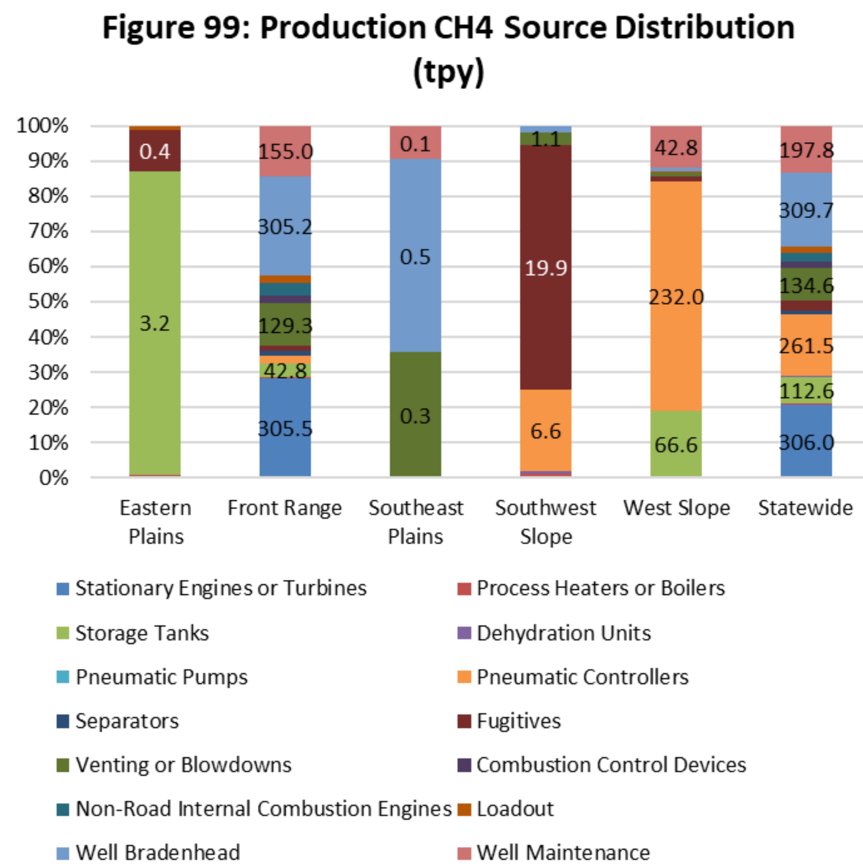
The average production VOC emissions estimates per well for OGDPs approved in 2022 was highest in the Southwest Slope (Figure 96), whose emissions primarily come from the use of engines or turbines on location, and VOC contained in the natural gas produced here is low. Statewide, production VOC emissions primarily come from Storage Tanks, which include a combination of produced water and oil/condensate tanks, Venting or Blowdowns and Stationary Engines or Turbines (Figure 97).





The average production methane emissions estimates per well for OGDPs approved in 2022 is highest in the Southwest Slope (Figure 98). These Southwest Slope emissions are primarily Pneumatic Controllers and Fugitive emissions, which are subject to statewide AQCC control requirements for these sources. Statewide, production methane emissions primarily come from Bradenhead, followed by Stationary Engines or Turbines and Pneumatic Controllers (Figure 99). Bradenhead emissions appear to be a significant contributor to the increase in per well methane emissions between 2021 and 2022. While there is no expected increase in this activity, it is reflective of better understanding of how to estimate these emissions, likely influenced by the requirement to evaluate these emissions for permit applicability under Routine or Predictable Emissions (ROPE) Air Pollution Emission Notices (APENs) beginning in 2021.





The average production HAP emissions per well for OGDPs approved in 2022 is highest in the Southwest Slope (Figure 100). However, this Southwest Slope region includes one OGDP with one OGDP Location and two wells; information about additional OGDP Locations in this area would be necessary to understand whether this is representative of development in the area. Statewide, production HAP emissions primarily come from Storage Tanks, which include a combination of produced water and oil/condensate tanks, followed by Stationary Engines or Turbines and Venting or Blowdowns (Figure 101).

Figure 100: Production HAP Emissions Per Well

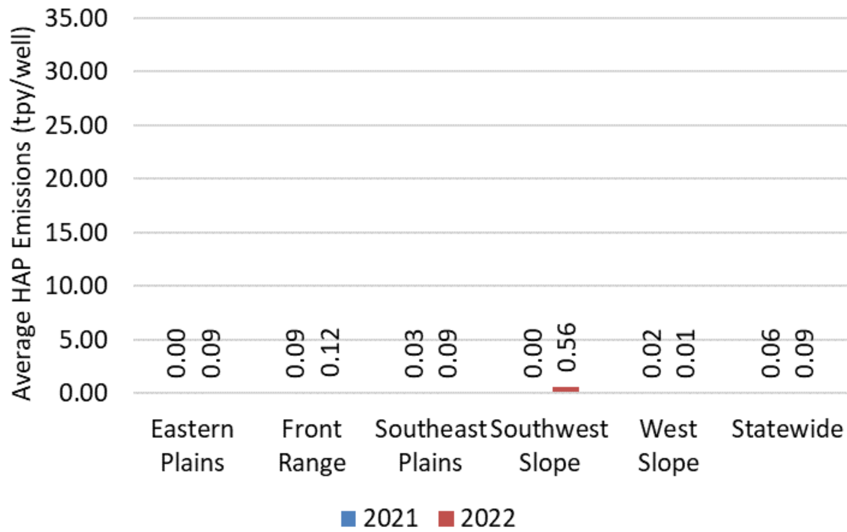
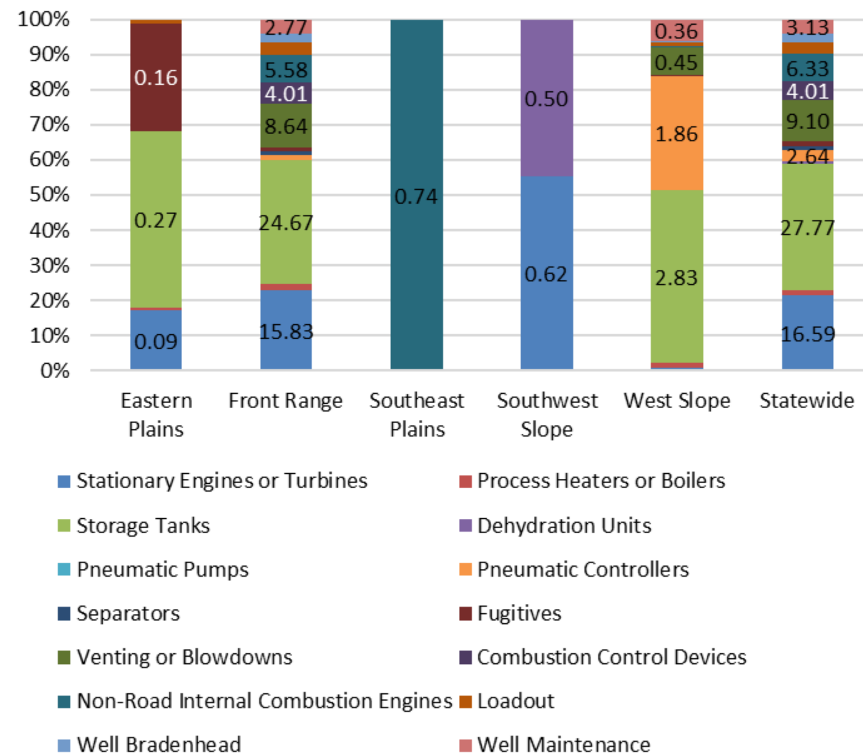
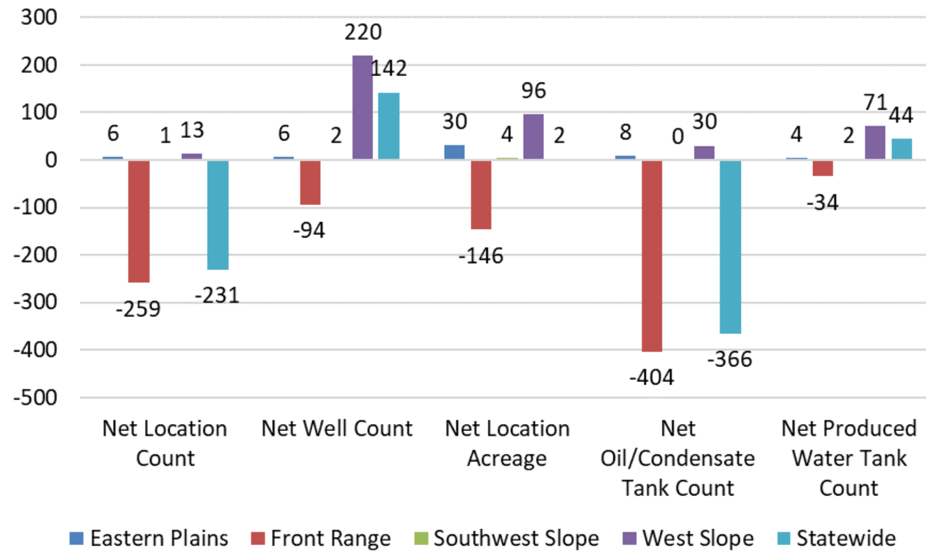


Figure 101: Production HAP Source Distribution (tpy)



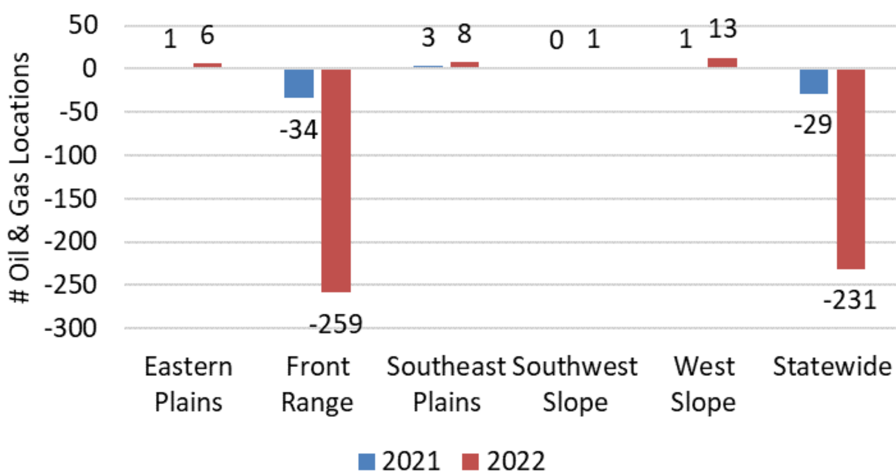
Net Impacts

Figure 102: Net Impacts



Some impacts will have a beneficial offset, as presented in Figure 102, with a year over year breakdown included in Figures 103 through 107. The net value takes into account the wells PAd, existing well pad count and associated acreage reclaimed, and tanks removed as estimated in the Form 2B. Information about the actual location and well to be reclaimed or plugged, respectively, has been required as a COA ordered by the Commission during the hearings for the associated OGDPs. The subsequent completion of these activities, although provided in CIDER during the 2022 calendar year, may occur over many future years; these activities should not be assumed to all be complete within a year. In addition, actual PA activities may be conducted for reasons in addition to these OGDP approvals; actual PA activities and net well counts are elaborated on in the Statewide Spud, Abandonment, & Orphaned Well Numbers section below. While there is a net increase in the number of wells permitted and potentially drilled, there will be a net decrease in the number of Oil and Gas Locations and the number of storage tanks, both produced water and oil/condensate, in the future as older, existing wells are plugged, tanks are decommissioned, and locations are reclaimed. The construction surface disturbance for new OGDPs is offset by the acreage of existing locations to be reclaimed.

Figure 103: Net Location Count



Net impacts for surface disturbance considered the construction surface disturbance when calculating this net impact. The construction surface disturbance is not the long term impact, and its use in this calculation recognizes the total impact to the new location. The surface disturbance post-interim reclamation will be smaller in many cases, resulting in a greater net decrease in surface disturbance.

Figure 104: Net Well Count

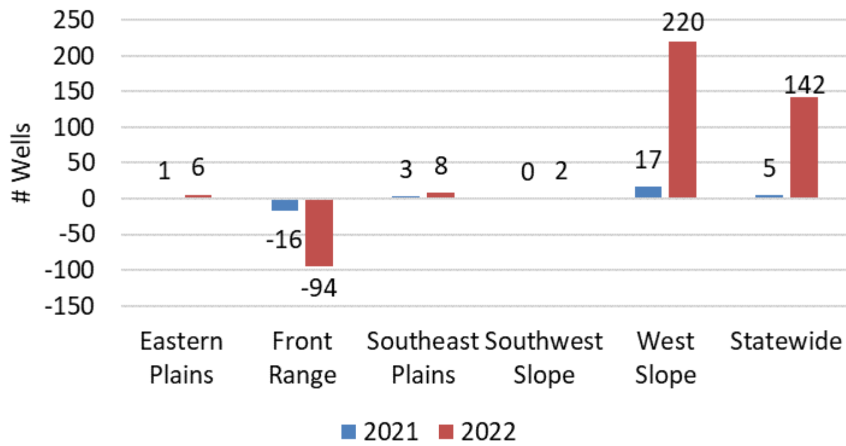


Figure 105: Net Disturbed Acreage

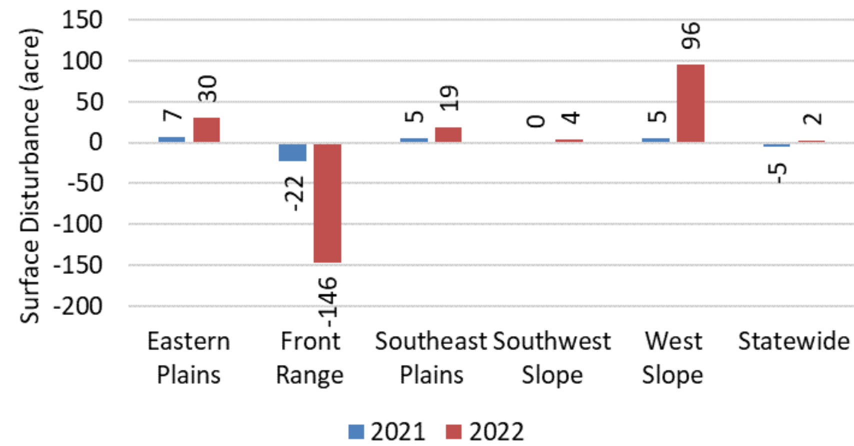


Figure 106: Net Oil/Condensate Tank Count

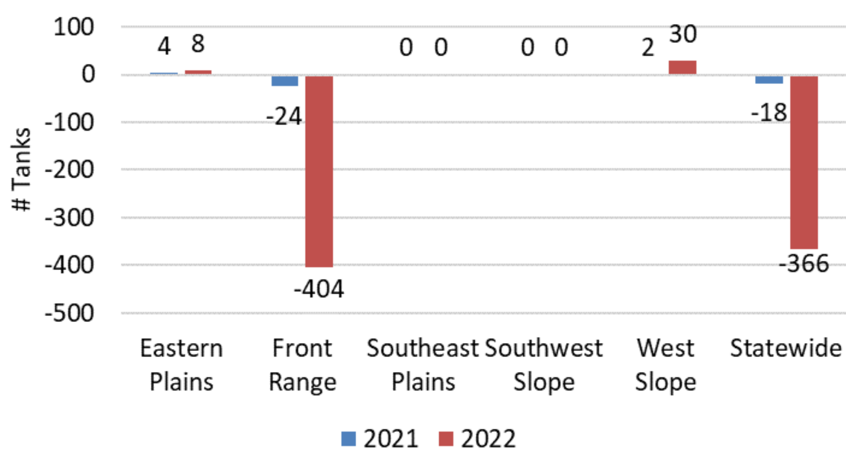
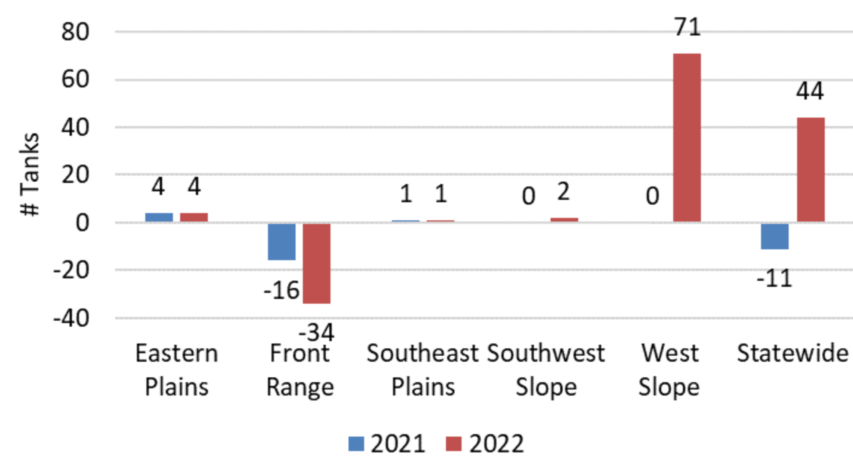


Figure 107: Net Produced Water Tank Count



Data Sources and Considerations

This Report on the Evaluation of Cumulative Impacts includes an assessment of data in CIDER. CIDER is solely a data repository and not a data evaluation program. CIDER is a compilation of the data entered on the Form 2B. The Form 2B includes hundreds of data fields entered by operators at the OGDP Location level as well as dozens more at the OGDP level. Staff acknowledges that the quantitative data in CIDER are not always sufficient to fully evaluate cumulative impacts and that some of the data are more suitable as or paired with spatial reviews. For example, there were 155 RBUs reported to be within 2,000 feet of the OGDP Locations approved in 2022 in the Front Range; while this version of the report further breaks out the distance within 2,000 feet of the RBU, it does not indicate whether the RBUs are dispersed within this radius or more densely concentrated in one neighborhood, etc.

Certain CIDER data are categorized as impacts estimated (or measured) either during the pre-production phase of operations or the production phase. Pre-production impacts are temporary and vary in intensity and duration; these include pad construction, drilling operations, and well completions, all of which can be a relatively short duration depending on the well characteristics and/or physical setting. Pad construction may have intense levels of activity with heavy equipment and is similar to other conventional earth moving construction projects. Drilling operations vary in duration depending on well type and number of wells. Well completions also vary in intensity and duration, and impacts (primarily noise and emissions) also vary depending on the equipment used. Drilling and well completion operations can occur concurrently, or a period of time may pass between one activity and the other (i.e. the Operator conducts multiple occupations on the Location over time). Comparatively, production operations are relatively constant and certain impacts may decline over time (i.e. produced water volumes typically decline along the Front Range resulting in reduced truck traffic over time).

Because Form 2As and Form 2s are valid for three years after OGDP approval and drilling can commence at any time within that time frame, the impacts on receptors near multiple OGDP Locations will vary depending on whether the operations at the different locations are conducted at the same or different times. These potential impacts may include increased noise, light pollution, odors, truck traffic, temporary reduction in scenic views, and increased emissions.

Although CIDER can be useful for determining potential cumulative emissions in an area (i.e. Front Range), it does not always contain certain information that is needed to determine the actual intensity and duration of emissions in localized areas. This is because operations at OGDP Locations that are proximate to each other may occur within the same time frame. Some OGDPs approved in 2022 include agreements by operators to minimize or postpone certain activities (such as postponing flowback) on forecasted Ozone Action Days along the Front Range, however, this timing consideration is not a data element in CIDER.

The CIDER data for emission estimates are segregated by pre-production activities (pad construction, drilling and completions) and production activities. The pre-production impacts on air quality are temporary and the cumulative impacts in an area are dependent on the timing of operations at different locations. Operations that occur simultaneously at multiple locations will have a potentially greater short term impact than operations conducted at different times. The potential impacts that production operations have on air quality are relatively longer term and constant. However, the impacts on localized areas with multiple OGDP Locations will vary depending on when production commences at each location.

CIDER's wildlife habitat data are useful for understanding the proximity to habitats and the acreage of land within habitats that would be displaced by oil and gas associated operations. Although many of the potential impacts to wildlife depend on when operations are conducted as related to various sensitive wildlife seasons, CIDER data do not include operational timelines or anticipated dates of activity. Operators often plan to conduct pre-production operations outside of the sensitive seasons for wildlife habitats to reduce the impacts from nuisances such as noise, light, and truck traffic. These considerations are included in Staff's and Operators' consultations with CPW and noted in Operators' Wildlife Plans attached to the Form 2A. Such consultations may result in operational timing limitations applied to the application as conditions of approval.

Data are presented above in somewhat simplified graphics with the intent to most readily inform the Commission and the public. It is important to note, however, that the evaluation of such data may be more informative or appropriate through review of associated diagrams or maps found within individual OGDP or CAP applications. Additionally, qualitative data collected on the Form 2B can be difficult to evaluate, as descriptive language can sometimes be interpreted in more than one way and cannot easily be measured for accuracy or bias.

Finally, values collected via CIDER may not be indicative of long term impacts. For example, operators may submit Form 4 Sundry Notices to reflect changes to equipment on location such as decommissioning tanks if oil takeaway pipelines are installed, which would reduce tank capacity and tank emissions. The values entered in CIDER are those data anticipated by the Operator during the planning of the OGDP Location. Changes in technology, best management practices, third party infrastructure, and other external influences may result in operational changes, and therefore impact changes, over time as operation continues.

904.a.(2) Greenhouse Gas Roadmap

GHG Roadmap

In 2019, House Bill 19-1261 Climate Action Plan to Reduce Pollution established statewide goals to reduce greenhouse gas emissions by 26% by 2025, 50% by 2030, and 90% by 2050 compared to a 2005 baseline. In January 2021, Colorado released its Greenhouse Gas Pollution Reduction Roadmap, which is a comprehensive roadmap identifying how state agencies will contribute to achieving these goals. The various Mission Change Rulemakings and Financial Assurance Rulemaking adopted by the Commission were significant towards the COGCC's contribution to these goals. Every other year, the APCD is required to provide a progress report to the Colorado Legislature, the first of which was submitted in December 2021 and discussed in last year's Cumulative Impacts Report.

In October, 2022, the APCD and CEO provided an update to the AQCC on the GHG Reduction Goals. During this presentation, the CEO shared its plans towards the Colorado GHG Roadmap 2.0. This updated roadmap will again be a multi-agency effort to identify additional strategies to pursue to make further progress towards GHG reduction goals. Since the publication of the first roadmap, there have been advancements in renewable and GHG reduction technologies, and the Inflation Reduction Act and the Infrastructure Investment and Jobs Act have both provided opportunities to receive additional funding and to reassess how to best distribute state resources. Additional priorities of this updated roadmap include more education and outreach, holistic solutions that address interconnected problems, tailored approaches for communities' unique needs, and environmental justice. The updated GHG Roadmap 2.0 will also address the role of a number of emerging technologies including carbon management, clean hydrogen, and advanced geothermal technologies. The CEO anticipates this updated roadmap to be completed by the end of 2023.

Progress with the GHG Roadmap is shared via biannual interagency reports published on the CEO webpage. The June 2022 and December 2022 reports summarize actions, and calls out significant new work between reports; certain information related to oil and gas are summarized below. Included in these reports and also published on the CEO website is the 2022 Legislative Session Snapshot, which identifies actions from the Colorado Legislature that advance climate and air quality.

GHG Inventory

In 2019, Senate Bill 19-096 Collect Long-term Climate Change Data was also adopted which requires GHG-emitting entities to monitor and report their emissions in support of Colorado's GHG Inventory. This GHG Inventory is required to be published no less frequently than every two years starting in 2019; the 2021 Greenhouse Gas Inventory Update remains the current version, and the inventory will be updated in 2023.

In October 2020, the AQCC adopted its Resolution to Ensure Greenhouse Gas (GHG) Reduction Goals Are Met (GHG Resolution). Among other things, this GHG Resolution required APCD to develop a GHG Dashboard to track critical variables or metrics on a monthly basis that may inform GHG trends between the GHG Inventory publications; this dashboard does not track actual emissions more frequently than the GHG inventory updates every two years. This GHG Dashboard was rolled out in March of 2022.

The APCD also met its obligation from the GHG Resolution to “evaluate the major drivers of emissions tracked in the [GHG] dashboard… and evaluate whether the projections and assumptions underlying the final [GHG] Inventory issued in 2021 have borne out” with its update to the AQCC in 2022 and the associated written report. The GHG Resolution established sector specific GHG emission targets for 2025 and 2030. The APCD interpolated a projected 2021 inventory based on this model and compared it to 2021 estimates. Of note, and discussed below, Colorado is still finalizing much of its actual reported oil and gas emissions through ONGAEIR, which will be used to inform portions of the economy-wide inventory going forward. This along with many other items explained further in the report provide important detail and context around availability of data and data limitations, which should be reviewed carefully. For example, explained is the use of the EPA State Inventory Tool (SIT) and actual reported information that Colorado will use to compile its GHG inventory. Table 5 summarizes this comparison.

Of note, the report states that “although there are GHG emissions associated with the production of fossil fuels, an increase in production may not always result in a corresponding increase in GHG emissions in Colorado. For example, oil and natural gas production increased significantly in Colorado from 2005 - 2019 (natural gas production +90%; oil production nine-fold increase), but GHG emissions only increased by 1.5% from the oil and natural gas sector during that time due to regulatory actions taken by Colorado to reduce emissions from oil and natural gas production. Colorado has taken further action to reduce the GHG intensity of oil and natural gas production establishing increasingly more stringent limits on the GHG emissions associated with oil and gas production.” The APCD went on to explain in the presentation and report that “While additional work needs to be done to ensure that the expected reductions will be achieved, the state has adopted and/or identified strategies that are expected to meet or exceed the sector-specific targets identified in the [GHG] Resolution for each of the sectors except transportation.”

Table 5: Comparison of Reported & Inventory-Based GHS to the 2021 GHG Projections

2019-2021 Reported & Inventory-Based GHGs and 2021 GHG Projections (MMT CO2e)[13]					
Sector	Value Source	2019 GHGs Reported & Inventory	2020 GHGs Reported or Calculated	2021 GHGs Reported or Calculated	2021 GHGs Projection Inventory
Electricity	Reported	33.87	29.58	31.40	23.43
Natural Gas & Oil Systems	Reported	NA	5.69*	Incomplete*	18.93
	Inventory	20.26	NA	NA	
Transportation	Reported	NA	28.83	33.11*	24.99
	Inventory	27.44	NA	NA	
Residential, Commercial, Industrial (RCI) Fuel Use	Reported	14.6	26.97	16.48*	27.27
	Inventory	7.8*	NA	NA	
	Combined	22.4	27.81	Pending	
Agriculture	Reported	NA	NA	NA	10.66
	Inventory	10.66	Pending	Pending	
Coal Mining & Abandoned Mines	Reported*	0.44	0.37	0.31	1.81
	Inventory*	0.24	Pending	Pending	
	Combined	0.68	Pending	Pending	
Industrial Processes	Reported*	2.97	2.78	2.61	4.46
	Inventory*	3.06	Pending	Pending	
	Combined	5.98	Pending	Pending	
Waste Management	Reported*	1.64	1.21	1.36	4.48
	Inventory*	0.63	Pending	Pending	
	Combined	2.27	Pending	Pending	
Total (Reported Only)		**53.52**	**86.76**	**85.96**	**115.73 (Inventory Projection)**
Total (Reported + Inventory)		**123.56**	**Pending**	**Pending**	

[13] From GHG Reduction Goals Progress Report to Air Quality Control Commission - August 2022 pages 12 and 13. The cells with an "*" are footnoted in the source report.

Certain Agency & Legislative Efforts

There have been many efforts by various Colorado agencies to advance the GHG roadmap, a list of completed and planned regulatory actions are listed here.

Completed GHG Roadmap Regulatory Actions

- Low Emission Vehicle Rule (AQCC 2018)
- Zero Emission Vehicle Rule (AQCC 2019)
- Colorado GHG Reporting Rule (AQCC 2020)
- Hydrofluorocarbon (HFC) Phase Out (AQCC 2020)
- Approval of Utility Clean Energy Plans (PUC 2020-2021)
- Oil and Gas Direct Regulation and GHG Intensity Rule (AQCC 2021)
- GHG Emission and Energy Management for Manufacturers (GEMM) Phase I Rule (AQCC 2021)
- Mission Change Rulemaking (COGCC 2020-2021)
- Recovered Methane Rulemaking (AQCC 2022)
- Clean Heat Plan Rulemaking (PUC 2022)
- Financial Assurance Rulemaking (COGCC 2022)
- GHG Pollution Reduction for Transportation Planning (CDOT 2021)

Direct to the COGCC, the Financial Assurance Rulemaking, Orphaned Oil and Gas Well Enterprise, and CSU work studying the emissions from orphaned and PA'd wells together reduce GHG emissions as well as better understand the emission reductions.

The AQCC has a rulemaking scheduled for the GHG Intensity Verification in 2023. The December 2021 AQCC Rulemaking adopted an upstream GHG intensity rule, allowing operators the flexibility to determine which measures they will employ to meet predetermined intensity reduction targets, which are targets for GHG emissions per unit of oil and gas production. This 2021 rule identified the need for operators to submit annual verifications to the APCD, and instructed the APCD to submit a petition for rulemaking to the AQCC detailing how operators will demonstrate compliance with these verifications. A draft protocol and rule language were released for public comment in January 2023.

Planned Agency Rulemaking

- Receive and consider first Clean Heat Plans (PUC 2023)
- GEMM Phase II Rule (AQCC 2023)
- Building Performance Standards (AQCC 2023)
- Oil and Gas GHG Intensity Verification (AQCC 2023)
- Advanced Clean Truck Rule (AQCC 2023)
- Advanced Clean Cars II (AQCC 2023)
- Clean Heat Target Rulemaking (PUC 2022)
- Solar and Electric Ready Building Code Requirements (Energy Code Board 2023)
- Midstream Oil and Gas Rule (AQCC 2024)

904.a.(3) APCD Oil and Gas Emissions Inventory

In 2019, the AQCC adopted a new annual emissions reporting requirement in Regulation Number 7 Part B Section V (Oil and Natural Gas Operations Emissions Inventory Reporting). As a result, the APCD stood up the Oil and Natural Gas Annual Emissions Inventory Reporting program, or ONGAEIR. The most recent annual reports were submitted in June 2022 and covered emissions from the full 2021 calendar year; these submissions totaled 187 reports from 145 companies.

In 2022, the APCD created and implemented a new database and associated submission process to allow the APCD to more quickly and easily review and compile information in these reports, ultimately improving transparency and data sharing. Because the database was not ready to receive reports directly into the system by the June 30 deadline, the APCD accepted email submittals to meet the regulatory deadline and extended the deadline for operators to submit their reports through this new system. The process to submit ONGAEIR reports directly into the database was rolled out in the third quarter of 2022 and most reports were uploaded to the new database by the end of 2022. The APCD continues to work through issues with remaining operators to get all data into the database, which is expected to be complete in early 2023. As of December 31, 2022, the database had been populated with approximately 122 of the 187 reports submitted. Note that while some delays were due to operators' inaccuracies or errors identified through the validation portion of the process, many of the delays were related to issues in the validation system and database functionality, and the APCD has been working and continues to work diligently with the Governor's Office of Information Technology (OIT) to resolve them as quickly as possible. This work continues into 2023.

As part of its evaluation of cumulative impacts, this report intends to include the comparison of estimated emissions as submitted by the operator into CIDER and the actual emissions as reported in ONGAEIR when feasible. *The future ability to compare actuals to estimates will be perhaps one of the most powerful tools for the evaluation of cumulative impacts that the COGCC has.* However, no such comparison was possible this year, and this comparison, while exceptionally meaningful, will be complicated to track over time under the current requirements of CIDER and ONGAEIR. For every OGDP Location, pre-production emissions in CIDER are the total of emissions estimated for all pre-production activities, including construction, drilling, and completions. However, pre-production activities may not all take place in a single calendar year, and may not all be reported to ONGAEIR in the same calendar year.

For example: the CIDER data for one OGDP which was approved by the Commission in 2021 describes pre-production activities and their associated emissions estimates for construction of the pad, and the drilling and completion of 24 wells. Bayswater commenced pre-production activities (specifically pad construction and spudding of wells) in the fourth quarter of 2021. Based on this operational timeline, the actual data reported to ONGAEIR for 2021 only includes construction and drilling; since the wells were not completed in 2021, emissions from completions operations would not yet be reported to APCD. The wells were subsequently completed in 2022, which means Bayswater's ONGAEIR reporting for completions operations will not be submitted until June 2023. To further complicate matters, Bayswater only drilled and completed 12 of the 24 wells contemplated in their Form 2B CIDER estimates. So, in order to effectively compare CIDER emissions estimates with actual emissions reporting in ONGAEIR, COGCC will have to wait until Bayswater drills and completes their remaining 12 wells, and reports those emissions to ONGAEIR. This daylights a critical element regarding the comparison of CIDER estimates with ONGAEIR actuals; should pre-production activities span multiple calendar years, COGCC's ability to compare actual emissions to estimated emissions in CIDER will require significant time and careful coordination.

For production emissions, CIDER requires an estimate of the first year of full production, meaning the emissions occurring for one year once all the wells on the pad have been put into production status. It should be noted that the comparison of a full year of production emissions, will require two calendar year ONGAEIR reports. An OGDP Location that began full production in 2022 will require both the 2022 and 2023 ONGAEIR reports, which will not both be available until June 2024. Therefore, this hypothetical OGDP Location's comparison cannot be included in this cumulative impacts report until 2025. The timing considerations above necessitate a couple more years until the comparison of CIDER estimates to ONGAEIR actual emissions can be included in this annual report, and even more to obtain good momentum behind the information learned with the comparison. In the meantime, APCD Staff has engaged operators in discussions on how these CIDER emissions estimates are calculated, which will continue to improve the accuracy of these emission estimates.

COGCC and APCD Staff have discussed future planning and logistics in order to conduct the comparison of estimated emissions in CIDER to actual emissions reported through ONGAEIR. Previous discussions had indicated the importance of the ability to correlate APCD identifying information (i.e. AIRS ID) and COGCC identifying information (i.e. Location IDs). The 2021 calendar year reports are the first to include both sets of identifying information. COGCC and APCD Staff have further discussed challenges with comparing a full year of production information (CIDER value) to calendar year emissions when this first full year spans multiple calendar years (ONGAEIR). For example, an OGDP Location with a first date of production on June 1, 2022 will require both the 2022 and 2023 calendar year ONGAEIR reports to conduct this comparison. Further, these ONGAEIR reports currently collect emissions as an annual value, and only collect monthly emission values during ozone season months. The APCD is currently in the process of identifying further revisions to ONGAEIR reporting that will help with this comparison in the future as well as improvements in other APCD uses of this information. Should these ONGAEIR revisions require regulatory changes, the APCD is currently evaluating whether these changes can occur in the upcoming July 2023 rulemaking addressing the GHG Intensity Verification.

904.a.(4) Ozone Trends

Ozone Standards and Classifications

The United States Environmental Protection Agency (EPA) established an 8-hour ozone National Ambient Air Quality Standards (NAAQS) of 75 parts per billion (ppb) on March 12, 2008, commonly referred to as the 2008 ozone NAAQS. In an April 2012 action, the EPA issued their implementation rule for the 2008 ozone NAAQS which established air quality thresholds to define each of the five nonattainment classifications based on the severity of exceedance of the standard (*see* 73 FR 16436). When a region does not attain the standard in the timelines outlined in the Clean Air Act (CAA), the region is bumped up to the next classification. The classifications in order of severity are Marginal, Moderate, Serious, Severe 15, Severe 17, and Extreme. Each classification comes with more stringent permitting and construction requirements as outlined in the CAA.

In May 2012 the Denver Metro/North Front Range (DM/NFR) region of Colorado was designated as a marginal nonattainment under the 2008 ozone NAAQS based on how much it was exceeding the standard (*see* 77 FR 30088). Given the region's continued nonattainment, the EPA has continued to reclassify the region to higher levels of nonattainment under the 2008 ozone NAAQS. Most recently, in October of 2022, the EPA reclassified the DM/NFR to Severe 15 nonattainment area under the 2008 ozone NAAQS (*see* 87 FR 60926). The DM/NFR has until 2027 to attain the 2008 Ozone NAAQS or risk being reclassified again.

Following an extensive review of scientific evidence on the effect of ozone on public health and welfare, the EPA strengthened the 8-hour ozone NAAQS to 70 ppb to improve public health protection without revoking the 75 ppb standard (*see* 80 FR 65291). This additional standard is commonly referred to as the 2015 ozone NAAQS and initiated a separate, yet parallel, process for states to demonstrate attainment with the more stringent NAAQS. This new standard also comes with a revised geographic area for the 2015 Ozone NAAQS. In 2021, the EPA published a revision to Colorado's initial designation under the 2015 ozone NAAQS to include all of Weld County. Oil and gas locations within this new geographical area are subject to the CAA and state requirements applicable to the 2015 ozone NAAQS, but not the 2008 ozone NAAQS. Figure 108 shows the DM/NFR nonattainment area under each standard.

The DM/NFR region was initially classified as marginal nonattainment under the 2015 ozone NAAQS in a June 2018 action (see 83 FR 25776). In October of this year, given the region's continued nonattainment, the EPA has reclassified the DM/NFR to a moderate nonattainment area under the 2015 ozone NAAQS (see 87 FR 60897). The DM/NFR has until 2027 to attain the 2008 Ozone NAAQS or risk being reclassified again.

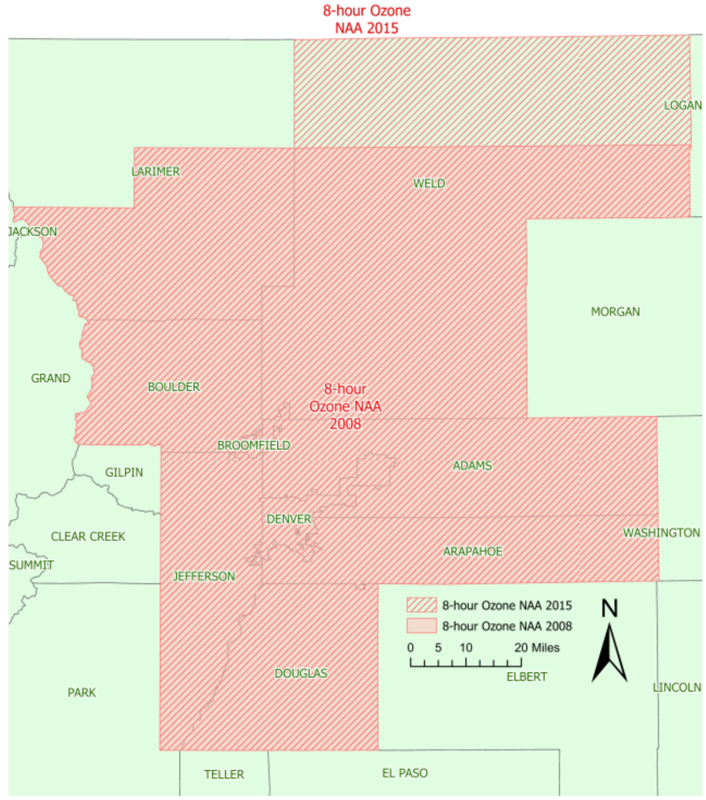


Figure 108: DM/NFR Nonattainment Areas

Ozone Season Report to Commission

On October 9, 2022, the Commission heard an APCD report on the 2022 summer ozone season. A few highlights from this presentation are included below.

Ozone, for the most part, is a secondarily formed air pollutant at ground level, resulting from the reactions of hydrocarbons with oxides of nitrogen (NOx), commonly called ozone precursors, in the presence of sunlight. Due to the meteorology in the DM/NFR area, the highest ozone values typically occur along the foothills due to upslope convection winds and reaction time. The two primary anthropogenic sources of ozone precursors are motor vehicles and oil and gas development, each accounting for up to 40% of the total emissions (depending on the ozone monitoring location).

Ozone levels in 2022 were generally lower across the DM/NFR area compared to 2021 and there were less days over the NAAQS, as shown in Figures 109 and 110, respectively. However, it should be noted that ozone was exceptionally high during 2021 due to a number of factors, including persistently high levels of wildfire smoke, hot temperatures, and very little precipitation. Wildfire smoke contains hydrocarbons and NOx, which are both ozone precursors. Massive amounts of wildfire smoke coincided with exceptionally hot and dry weather in 2021 to produce the worst summer ozone season since at least 2003 for the DM/NFR area.

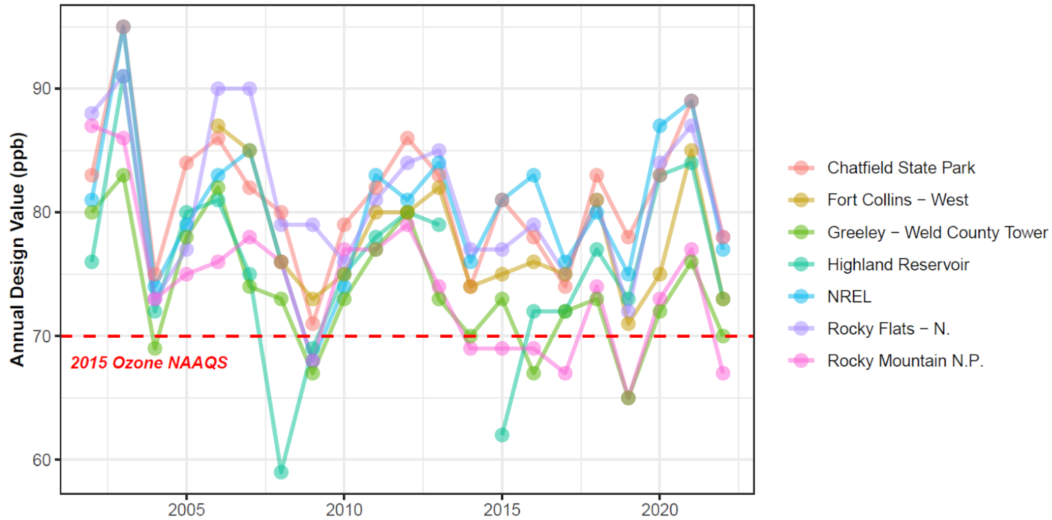


Figure 109: North Front Range 8-Hour Ozone Annual 4th Maximum

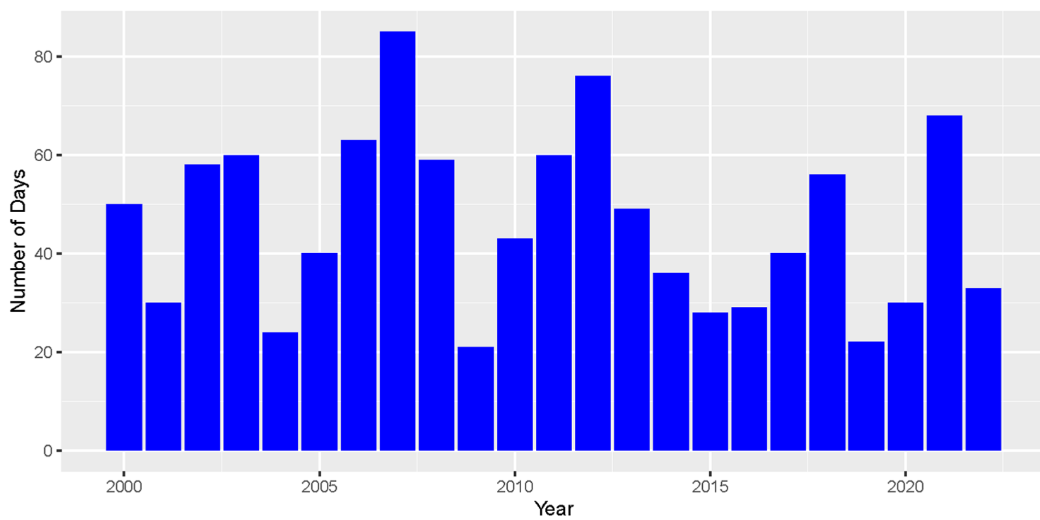


Figure 110: North Front Range Days Over the 2015 Ozone NAAQS

In addition, the 500 millibar geopotential height is often an indicator of surface air temperature and has a good correlation with summer ozone in the DM/NFR area. During the summer of 2021, it was the highest on record dating back to 1940. For 2022, the 500 millibar pressure height was similarly very high, however, ozone levels were noticeably lower than in 2021, as shown in Figure 111. The two most likely atmospheric factors for this decrease in ozone concentrations during the summer of 2022 were a significant decrease in the amount of wildfire smoke and a much more robust monsoon season. The increase in monsoonal moisture resulted in an upsurge of thunderstorm development which frequently disrupted afternoon ozone production.

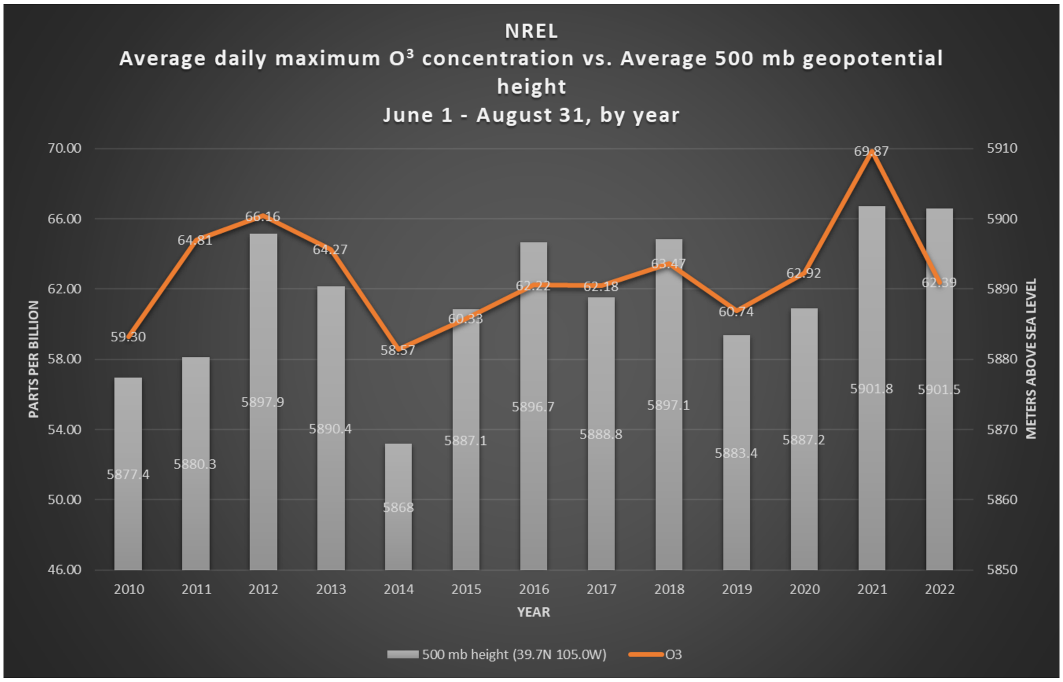


Figure 111: Average Daily Maximum O3 Concentration

Oil and Gas Contribution to Ozone

On January 11, 2023, the APCD and Regional Air Quality Council (RAQC) gave a presentation to the Commission on oil and gas contributions to ozone and the ozone SIP planning process. Similar information was presented to the AQCC in September 2022. A few highlights and supplemental information from the presentation to the COGCC are included below.

The APCD models the actual and projected emissions of ozone precursors and their resulting contribution to Ozone. In 2022, modeling was conducted using the most recent 2017 inventory (supplemental information can be found in TSD-003, TSD-007, and TSD-008 in the December 2022 Rulemaking Materials), which was updated in 2022, and projecting 2023 ozone levels. More information on this inventory and how it was modeled can be found in the 2021 Ozone Modeling Forum on the RAQC website. The following Figure 112 and Figure 113 summarize the oil and gas emissions contribution of NOx and VOC, respectively, in the 2017 inventory and modeled 2023 inventory.

Figure 112: 2017 Inventoried and 2023 Modeled NOx Emissions

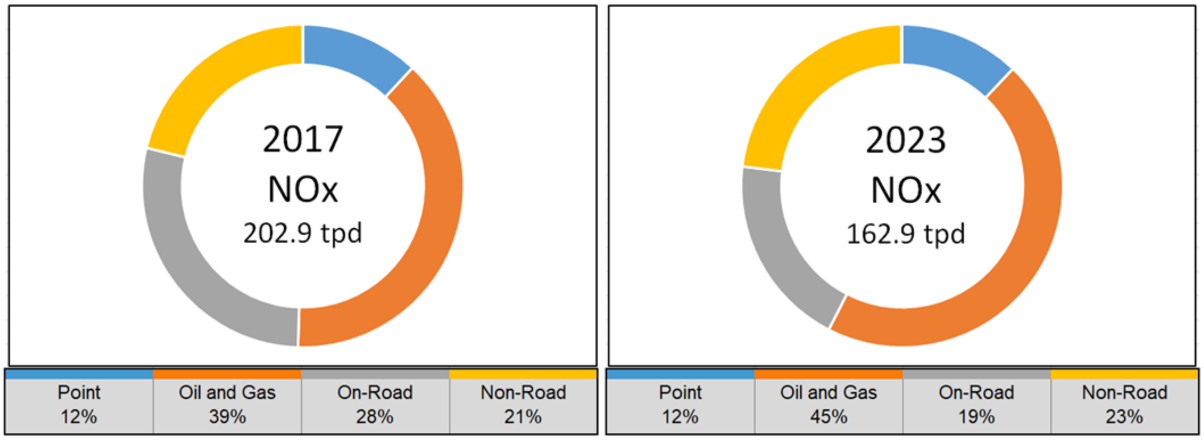
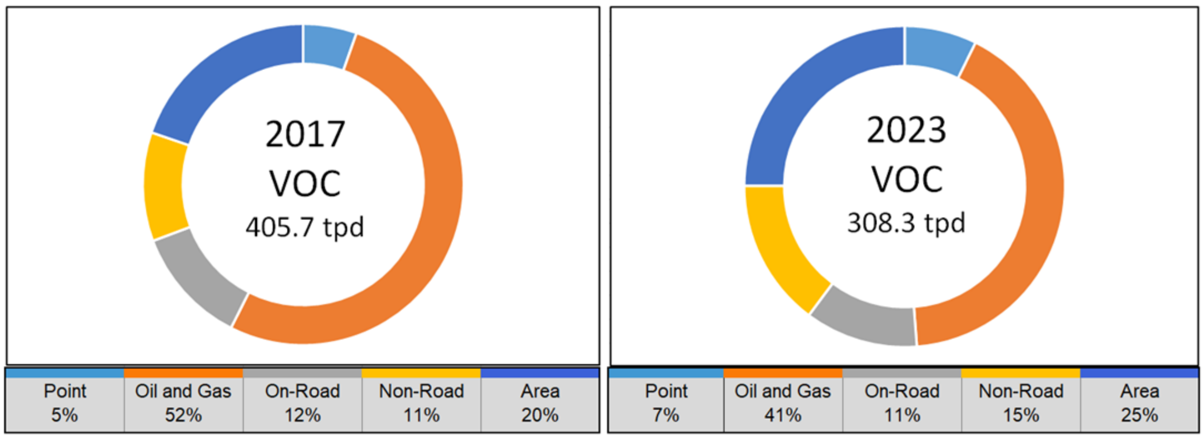


Figure 113: 2017 Inventoried and 2023 Modeled VOC Emissions



These emissions are then further modeled to estimate the maximum modeled contributions to ozone across the DM/NFR nonattainment area by varying source categories; the results of this are shown in Table 6. Please note that this modeling is not representative of a single monitoring location and instead represents the maximum modeled impacts occurring somewhere in the nonattainment area.

Table 6: Maximum Modeled Ozone Contributions

Ozone Source	Contribution	Includes
Oil and Gas	8.6 ppb	Area and point sources (operations, storage facilities, drilling, trucking and engine exhaust)
On-Road Vehicles	6.8 ppb	Light/Medium/Heavy Duty Vehicles (SUVs, cars, pickup trucks_
Non-Road Sources	5.4 ppb	Construction Operations, rail/train operations, agriculture
Point Sources	5.3 ppb	Industrial sources and electricity generation
Lawn & Garden	2.5 ppb	Commercial lawn equipment and residential lawn and garden equipment (mowers, leaf blowers,

Ozone Source	Contribution	Includes
		trimmers, etc.)
Area	1.2 ppb	Personal care products, cleaning products, paints, and solvents
Background and Natural	48.6 ppb	Background ozone, transport, local fires, plant-based emissions

State Implementation Plan

Areas with a moderate and greater ozone nonattainment classification must submit a State Implementation Plan (SIP) that, among other things, outlines the state's requirements that are intended to help it achieve attainment. As discussed above, ozone is not emitted directly, and is instead formed with the presence of ozone precursors and sunlight. While Colorado may have many regulations, programs, and strategies that help reduce ozone precursor emissions, a subset is included in the SIP and becomes federally enforceable[14].

In December 2022 the AQCC held a hearing to consider SIP elements proposed by the APCD and RAQC. These SIP Elements were developed according to requirements outlined in the Clean Air Act and EPA guidance in response to the DM/NFR being reclassified under both standards. Related to oil and gas, this rulemaking included additional controls of volatile organic compound emissions from oil stabilization facilities and class II injection well facilities, and several oil and gas requirements that were formally implemented at the state level were moved into the SIP including emission control requirements for large engines, pneumatic controllers, and truck loadout. The AQCC voted to approve the proposed elements and they are advancing to the Colorado legislature for review and approval prior to being submitted to the EPA. An additional rulemaking will be held in Fall 2023 to consider the remaining elements of the SIP under the 2008 ozone NAAQS and additional control programs to improve air quality in the DM/NFR.

Decreasing ozone concentrations in the DM/NFR is a continued priority for the APCD and RAQC. Sources of ozone precursors will continue to be examined to determine the best options for reducing emissions. Both agencies are working together to consider additional strategies which were identified in the AQCC December 2022 SIP Rulemaking to "include, at a minimum

- Prohibitions on gasoline-powered lawn and garden equipment sales, and further incentives for the conversion of gas-powered equipment to electric;
- Additional non-road equipment reduction strategies;
- Building and appliance efficiency standards;
- Residential auto maintenance incentives;
- Commercial diesel best practices initiatives;
- Advanced Clean Cars II standards;
- Strengthening the vehicle inspection and maintenance program;
- Mobile source credits as part of nonattainment new source review;

[14] Supplemental information can be found at RAQC.org, including this helpful Guide to the Ozone SIP.

- Additional/permanent funding for VMT reducing strategies such as zero-fare transit, increased transit services, and bicycle and walking infrastructure;
- Emission reduction approaches for indirect sources;
- Additional industrial source emission reduction requirements, such as flaring minimization requirements at applicable sources, episodic and seasonal restrictions on industrial and commercial activities, oil and gas pre-production activities, rules to reduce emissions from gas-fired reciprocating internal combustion engines (RICE) in the oil and gas sector, requiring emission offsets or aggregation of wellhead and production facility equipment when permitting oil and gas sector minor sources, and zero-emitting retrofits for all existing pneumatic devices;
- and any other measures that the Division determines would assist in attainment of the ozone NAAQS."[15]

In addition, the AQCC is planning additional rulemaking in 2023 to support the SIP.

904.a.(5) Evolving & New Innovative Technologies & Measures

The oil and natural gas industry has and continues to evolve. The following summarizes certain evolving or new and innovative technologies and measures that Staff has been made aware of. To assist the development of this section, a link was added to the Cumulative Impacts page of the COGCC website to collect additional information on an ongoing basis. Any information submitted on this webpage will be reviewed by staff for applicability and relevance, and may be included in subsequent reports.

In December 2021, the AQCC adopted additional control requirements for certain well liquids unloading activities beginning January 1, 2023. Emissions associated with well liquids unloading activities were not widely controlled prior to this rulemaking. In preparation for compliance, some operators began testing emission control equipment and methodologies as the unique flow rate and pressure prevents the use of existing control equipment. These new control strategies may include various combinations of temporary or portable separators, emission control devices or flares[16], and/or compression. Alternatively, some operators have begun exploring the wider use of alternatives to well liquids unloading, such as retrofits to well production equipment, or have begun using closed loop systems, which do not have emissions, to conduct this activity. The effectiveness of these alternatives to well liquids unloading and the ability to use the closed loop swabbing equipment depend on the well and facility conditions and must be evaluated on a site by site basis.

In February 2021, the AQCC adopted certain additional requirements to Regulation Number 7 for pneumatic controllers. These requirements include the development of operator specific company-wide plans, when applicable, to convert some of their existing facilities from the use of natural gas driven pneumatics to non-emitting controllers, such as instrument air driven pneumatics controllers, electric

[15] See Statement of Basis and Purpose December 15, 2022 (Revisions to Part A, Sections I., II., and Appendix A; Part B, Sections IV. and VI.; Part C, Sections I., II., III., and IV.; Part D, Sections I., II., and III.; and Part E, Sections I., II., III., IV., VI., VII., and VIII.)
[16] Compliant with COGCC Rule 903.

controllers, mechanical controllers, etc. Operators were then required to retrofit a certain percent of their facilities as defined by Regulation Number 7 by May 1, 2022 and May 1, 2023. As a result, instrument air has become more widely implemented throughout the state in 2022. In addition, operators have had more opportunities to test alternate no-bleed controllers, such as electric controllers or routing the natural gas line from a controller to a process, sales line, or combustion device. Process requirements, such as actuation time, can vary by location and equipment, so the ability to utilize a diverse suite of technologies remains critical to this program. Finally, for those locations still utilizing gas powered pneumatics, operators are exploring more sophisticated methods to track actual hours and bleed rates to report their emissions more accurately. This effort will result in much more accurate reporting of actual emissions when compared to the default values used previously.

ROPE permitting has increased recordkeeping and compliance tracking for certain activities traditionally considered exempt prior to 2021. One such ROPE activity is the opening of a thief hatch, whether it be for gauging a tank, collecting a sample, maintenance, etc. To improve accuracy of emission estimates, some operators have tested the use of thief hatch counters which record when a thief hatch is opened and closed. The more advanced this technology gets (e.g. the ability to notify someone if a thief hatch was left open), the more technological requirements are necessary, rendering its effectiveness location specific.

904.a.(6) Academic or Government Reports

Literature related to cumulative impacts to public health, safety, welfare, the environment and wildlife resources from oil and gas development are numerous. Below are academic or government reports published in 2022 that Staff is aware of related to the impacts of oil and gas activities that are not referenced elsewhere in this report.

Barker, R.E., A.D. Apa and R.S. Lutz. 2022. *Survival of Columbian Sharp-tailed Grouse Chicks and Juveniles in Northwestern Colorado*. Journal of Wildlife Management, 86:e22310. https://doi.org/10.1002/jwmg.22310 (Accessed February 2023)

Caldwell, J.A.; C.K. Williams, M.C. Brittingham and T.J. Maier. 2022. *A Consideration of Wildlife in the Benefit-Costs of Hydraulic Fracturing: Expanding to an E3 Analysis*. Sustainability, 14, 4811. https://doi.org/10.3390/su14084811 (Accessed February 2023)

Chambers, S., M.L. Villarreal, O. Duane, et al. 2022. *Conflict of energies: spatially modeling mule deer caloric expenditure in response to oil and gas development*. Landscape Ecology, 37.11: 2947-2961. https://doi.org/10.1007/s10980-022-01521-w (Accessed February 2023)

Crooks, J.L., Licker, R., Hollis, A.L. et al. 2022. *The ozone climate penalty, NAAQS attainment, and health equity along the Colorado Front Range.* J Expo Sci Environ Epidemiol 32, 545–553. https://doi.org/10.1038/s41370-021-00375-9 (Accessed February 2023)

Curran, M., T. Robinson, P. Guernsey, et.al. 2022. *Insect Abundance and Diversity Respond Favorably to Vegetation Communities on Interim Reclamation Sites in a Semi-Arid Natural Gas Field*. *Land* 11, no. 4: 527. https://doi.org/10.3390/land11040527 (Accessed February 2023)

Des Brisay, P.G., L.D. Burns, K. Ellison, et al. 2022. *Oil Infrastructure has Greater Impact than Noise on Stress and Habitat Selection in Three Grassland Songbirds*. Environmental Management. https://doi.org/10.1007/s00267-022-01752-2 (Accessed February 2023)

Deziel, N.C., B. Shamasunder and L. Pejchar. 2022. *Synergies and Trade-Offs in Reducing Impacts of Unconventional Oil and Gas Development on Wildlife and Human Health.* BioScience, 72: 472-480. https://doi.org/10.1093/biosci/biac014 (Accessed February 2023)

Gundlach, J.J. 2022. *Mule Deer Responses to a Pinyon-Juniper Removal.* University of Nevada, Reno. https://scholarworks.unr.edu/handle/11714/8283 (Accessed February 2023)

Jones, P.F., A.F. Jakes, S.E. Vegter, et al. 2022. *Is it the road or the fence? Influence of linear anthropogenic features on the movement and distribution of a partially migratory ungulate.* Mov Ecol 10, 37 (2022). https://doi.org/10.1186/s40462-022-00336-3 (Accessed February 2023)

Li L., F. Dominici F, A.J. Blomberg, et.al. 2022. *Exposure to Unconventional Oil and Gas Development and All-cause Mortality in Medicare Beneficiaries.* Nat Energy. 7, 177-185. https://doi.org/10.1038/s41560-021-00970-y (Accessed February 2023)

Marrotte, R.R., C.R. Anderson Jr. & J.M. Northrup. 2022. *Developing a spatial planning tool for natural gas development on mule deer winter range.* Final Report to Bureau of Land Management: Grant Agreement L18AC00068.14pp.

Reddy, P.J., C. Taylor. 2022. *Downward Trend in Methane Detected in a Northern Colorado Oil and Gas Production Region Using AIRS Satellite Data.* Earth and Space Science 9, 12. https://doi.org/10.1029/2022EA002609 (Accessed February 2023)

Sandoval Lambert, M., H. Sawyer, and J.A. Merkle. 2022. *Responses to Natural Gas Development Differ by Season for Two Migratory Ungulates.* Ecological Applications, 32(7): e2652. https://doi.org/10.1002/eap.2652 (Accessed February 2023)

Saracco, J.F., P. Pyle, D.R. Kaschube, et.al. 2022. *Demographic declines over time and variable responses of breeding bird populations to human footprint in the Athabasca Oil Sands Region, Alberta, Canada,* Ornithological Applications, Volume 124, Issue 4, 3, duac037. https://doi.org/10.1093/ornithapp/duac037 (Accessed February 2023)

Schissel, C., and D.T. Allen. 2022. *Impact of the High-Emission Event Duration and Sampling Frequency on the Uncertainty in Emission Estimates.* Environmental Science & Technology Letters, 9 (12), 1063-1067. https://doi.org/10.1021/acs.estlett.2c00731 (Accessed February 2023)

Wang, J.L, W.S. Daniels, D.M. Hammerling, et.al. 2022. *Multiscale Methane Measurements at Oil and Gas Facilities Reveal Necessary Frameworks for Improved Emissions Accounting.* Environmental Science & Technology 56 (20), 14743-14752. https://doi.org/10.1021/acs.est.2c06211 (Accessed February 2023)

Yu, J., B. Hmiel, D.R. Lyon, et.al. 2022. *Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin*. Environmental Science & Technology Letters 9 (11), 969-974 https://doi.org/10.1021/acs.estlett.2c00380 (Accessed February 2023)

Staff is also aware of ongoing studies, which will be reviewed for relevancy and may be included in the report covering the period of time in which they are published. Finally, reports may be submitted to Staff for review via the link on the Cumulative Impacts page of the COGCC website. Any academic or government reports or studies submitted on this webpage will be reviewed by staff for applicability and relevancy, and may be included in subsequent reports.

904.a.(7) Information Requested by Commission

Subparagraph 904.a.(7) invites the Commission to request, or the Director to include, additional information in this report. The purpose of this section is to introduce new information or topics that may be integrated into future Cumulative Impacts reports. Significantly, Commissioners discussed additional items they wish to be considered in this report in the December 8, 2022 Commission Hearing. At that time, the Director agreed to look at a series of items for feasibility once data were compiled, and this section is a result of this discussion and the subsequent review.

Statewide Spud, Abandonment, & Orphaned Well Numbers

Well spud activity is reported via Form 42 (Notice of Spud). Records of plugging and abandonment (PA) of wells are reported via Form 6 (Subsequent Report of Abandonment, SRA). Upon approval of these forms, the well status is updated and recorded.

In 2022, 932 notices of spud were reported via an approved Form 42. By contrast, 1102 wells were reported as PA'd via an approved Form 6 SRA, resulting in a net reduction of 145 wells (Figure 114)[17]. Both spud and plug and abandonment activities in the Front Range are primary contributors to these data with 84.2% and 94.6% of these spuds and PAs, respectively (Figure 115). The number of wells PA'd could be driven by time-dependent changes in reservoir characteristics of the basin, social considerations for areas with higher population density, economic burden for operators related to market fluctuations, compliance burden in the nonattainment area, OGDP permitting considerations, and/or other factors.

[17] The continued processing and approval of Form 6s may result in later changes to these values. Indeed, the updated number of PAd wells in 2021 is 1,442.

Figure 114: 2022 Spud, PA, Net Well County by Operating Area

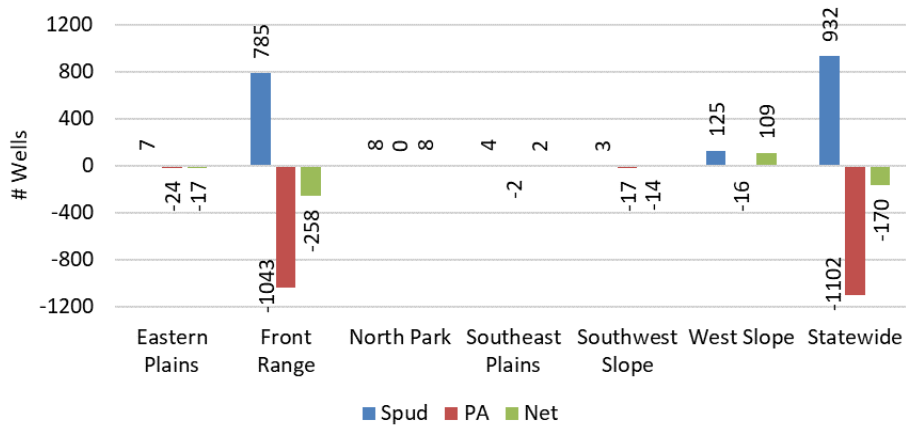
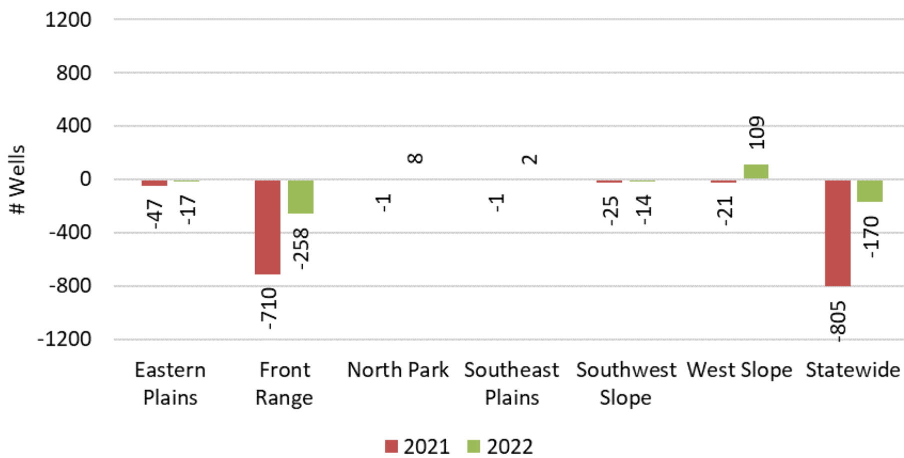
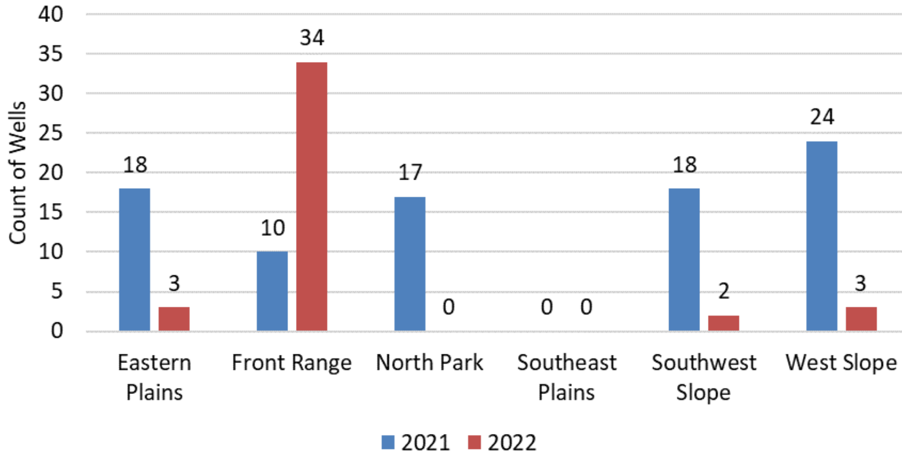


Figure 115: 2022 Net Well Count by Operating Area



The COGCC Orphaned Well Program (OWP) identifies, prioritizes, and addresses oil and gas wells, locations, and production facilities statewide for which there are no known responsible parties ("Orphaned Wells or Sites") or for which financial assurance instruments have been claimed. While the OWP's responsibilities are numerous (e.g. environmental remediation, reclamation, equipment decommissioning, etc.), its PA activity is part of the total PA numbers above. In 2021 and 2022, the OWP Plugged 87 and 42 wells, respectively, a breakout of which by operating area are shown in Figure 116. More information on the Orphaned Well Program can be found in the annual reports and program website.

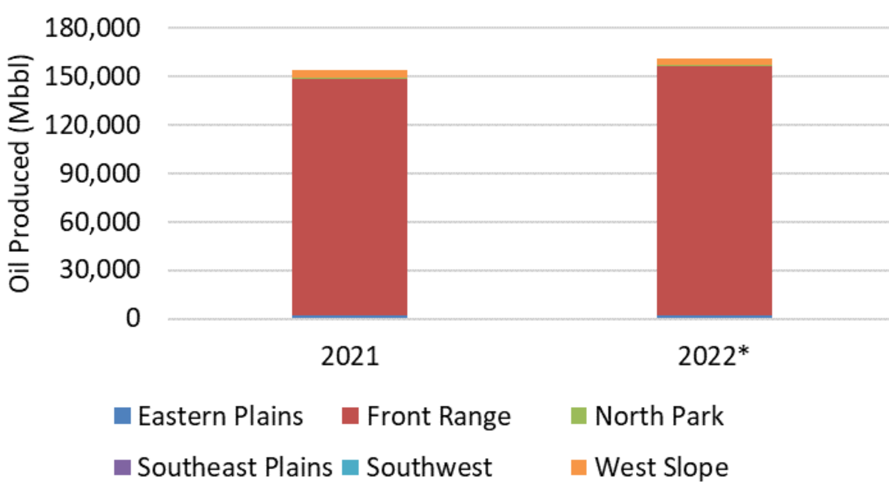
Figure 116: Wells Plugged by COGCC Orphaned Well Program



Statewide Production

At Commissioner request, an overview of statewide production follows in Figures 117-120[18,19]. However, production for each month is not finalized until 75 days after the close of a month, which means that production for the full year will not be prepared at the time of this report. Therefore, production for 2022 is represented by the twelve-month period from December 2021 through November 2022 for the purpose of this report only. Subsequent reports will update these values in the year over year comparisons. As a result, the information shown here reflects year over year information only as final values may change.

Figure 117: Oil Production



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[18] Gas Production includes natural and coalbed gas, carbon dioxide, and coalbed methane as provided in COGCC production downloads. Barrels of oil equivalent (BOE) was calculated with 6 mcf/boe and excludes CO_2 produced, as CO_2 has no heating value, therefore no equivalent.
[19] Natural Gas Production is a sum of Natural and Coalbed Gas, Carbon Dioxide, and Coalbed Methane.

Figure 118: Gas Production

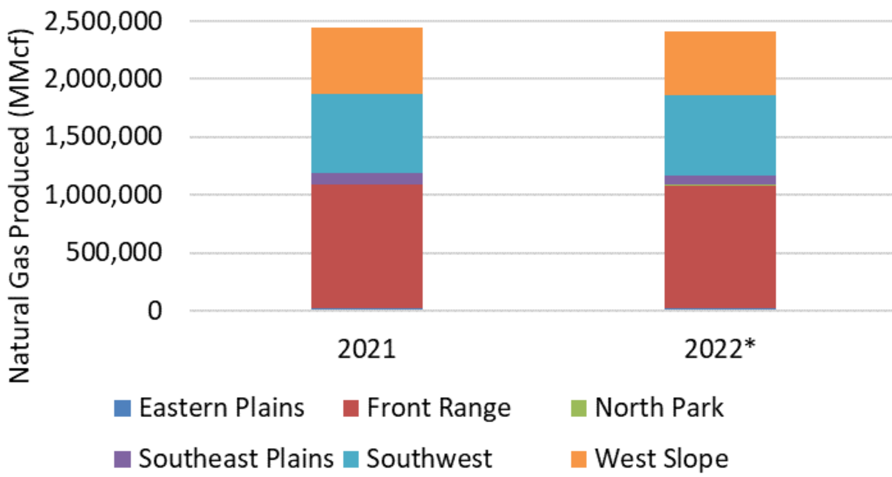


Figure 119: Water Production

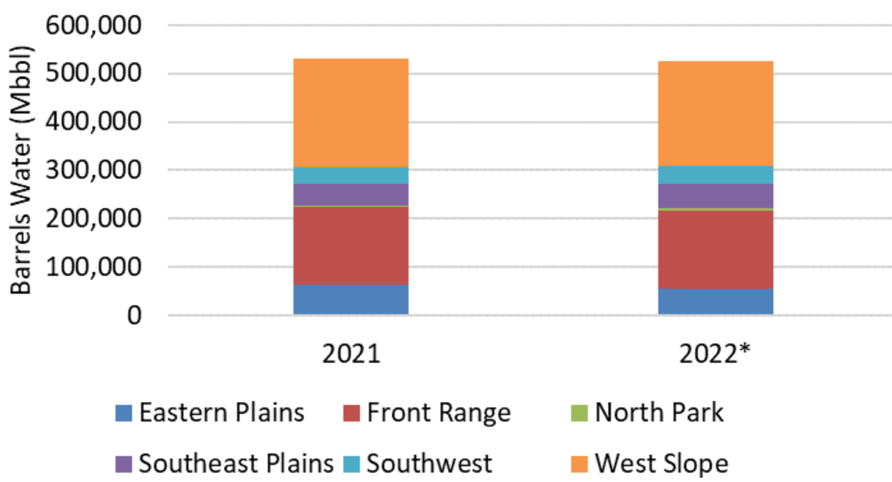
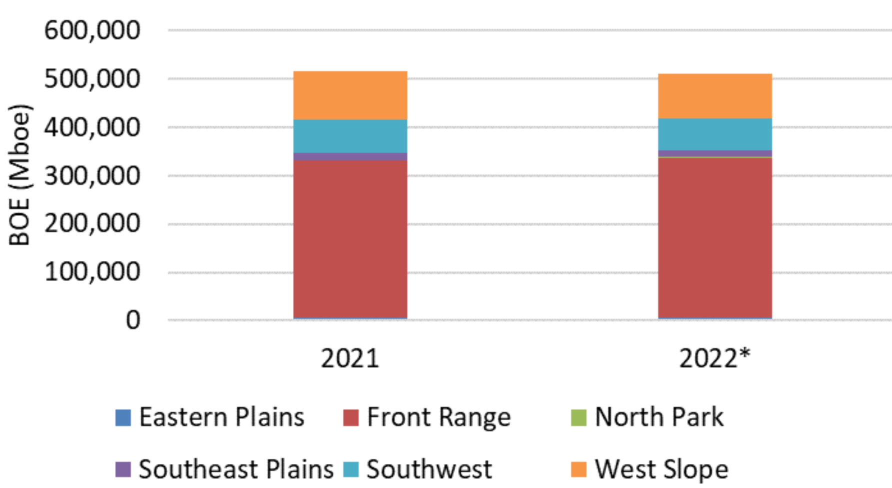


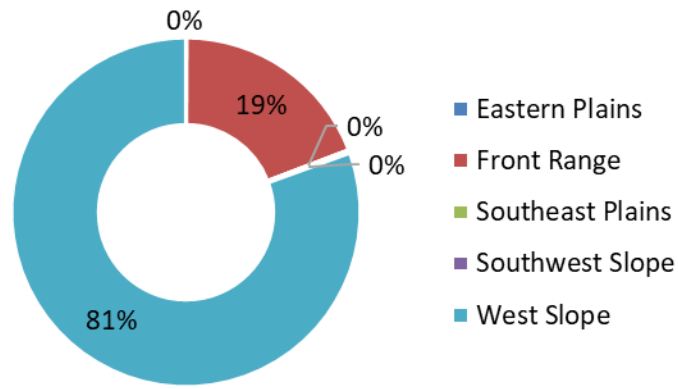
Figure 120: BOE Produced



Finally, Staff cautions the causation or correlation of production information with other information contained in this report. It is difficult to parse out the impacts on oil and gas production as a result of COGCC Mission Change Rulemaking and/or successive actions of the Commission versus other impacts to the oil and gas industry locally and nationally. For example, the COVID-19 pandemic lowered demand for energy in 2020 and 2021, which subsequently decreased production and development in both Colorado and the U.S., according to data from the U.S. Energy Information Administration. The remaining impacts from the pandemic-induced demand reduction and supply chain disruptions will continue to be commingled with any possible impacts from this Commission.

Well Liquids Unloading

Figure 121: 2022 Well Liquids Unloading by Operational Area



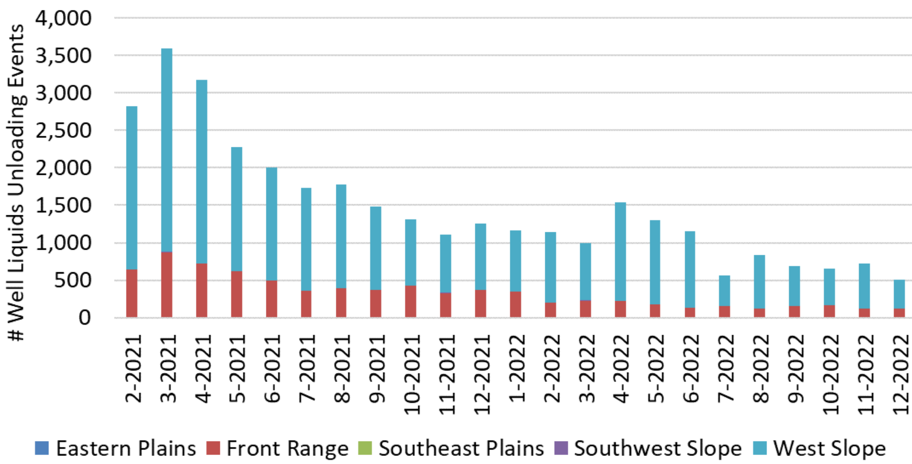
During the Mission Change Rulemaking, changes to Rule 903.d.(1) and 903.e addressed well liquids unloading activities, which are maintenance operations or other operations where there is intentional release of natural gas from the wellbore to the atmosphere in order to facilitate the unloading of liquids from the wellbore. One such requirement was for advanced notice prior to conducting this activity beginning January 2021[20]. Well liquids unloading is notified via a Form 42, which captures the intent to unload; the actual number of well liquids unloading events may be lower. In 2022, 11,280 well liquids unloading events were noticed, which is a little less than half of the 22,909 events noticed in 2021 (Figure 121)[21]. The majority of the well liquids unloading noticed in 2022 occurred in the West Slope, followed by the Front Range; only 37 events (0.33%) occurred between the Eastern Plains and Southwest Slope, and no liquids unloading was noticed in the Southeast Plains.

Since these liquids unloading notices began, there has been a general decreasing trend in count of well liquids unloading events (Figure 122). While there may be a variety of reasons for this, Staff notes a few actions suspected contribute to this trend. First, this new requirement to submit notice increased operator awareness of this activity. Additionally, the AQCC adopted requirements to submit APENs for ROPE in December 2019, which may also trigger permits for these activities. ROPE APENs include a variety of activities, of which well liquids unloading is one. APEN due dates varied by location, with all required to be submitted by June 1, 2022. The need to not only permit these activities but to include the emissions with other ROPE emissions on a location likely impacted operator decisions to conduct this activity. Finally, in December 2021, the AQCC adopted additional control requirements for well liquids unloading activities. These new control requirements included several best management practices, and also included requirements to control these activities beginning January 2023 for wells and/or locations

[20] The requirement to notice this activity began mid-January 2021. Because this was a partial month, it has been excluded from the monthly chart, and included in the 2022 count included in this paragraph.
[21] Staff is aware that confusion around the reporting requirements and process led to over-reporting these activities in early 2021; the information in this section includes all notices, which may increase these monthly values.

that exceeded certain well liquids unloading counts over specified time ranges which began in 2022, resulting in further reductions in 2022.

Figure 122: Monthly Well Liquids Unloading Counts by Operational Area



Emissions associated from these activities are also of interest to the Commission. Through ONGAEIR, the APCD is collecting actual emissions reported from well liquids unloading activities. This information may further the understanding of actual emissions from this activity when ready; however, as described above, the APCD is still in the process of collecting and reviewing this information.

Aerial and Ground-Based Surveys

Presentations including updates and preliminary results from CDPHE projects that received resources from the Martinez-Irwin Fund were given to the Commission and to the AQCC on August 31, 2022 and October 20, 2022, respectively. A written summary was provided to the Commision concurrently. Researchers representing the Colorado State University, University of Arizona, and University of Colorado Boulder/University of Maryland gave presentations to the Commission on October 7, 2022. The University of Chicago, Scientific Aviation, and the APCD gave presentations to the Commission on October 26, 2022.

The Mobile Oil/Gas Optical Sensor of Emissions (MOOSE) was delivered to the APCD in 2021, and began collecting data in earnest in 2022. Of the studies, only one project has been completed and the research published in a peer-reviewed journal. The University of Arizona identified that the largest contributors of methane, defined as emissions larger than 10 kilograms per hour, were oil and gas operations and agricultural operations, but the portion of contributions were seasonal. The study observed that contributions were almost equal in the summer (50% oil and gas to 44% agricultural), however oil and gas was a larger contributor in the fall (79% oil and gas to 16% agricultural). They also observed that production (well-sites and/or tank batteries) were responsible for the majority of oil and gas source emissions, although the contribution was highly variable. These findings were combined with data from the San Joaquin Valley, Uintah, Permian, and Marcellus Basins and published in the journal *Proceedings of the National Academy of Sciences*.

904.a.(8) Recommendations

Subparagraph (8) of 904.a. solicits recommendations from the Director for future rulemakings, guidance, workgroups, or studies to address cumulative impacts. This second report includes numerous additional ways to look at CIDER data, such as new ways to present the data with an increased data set and year over year trends to understand how these impacts may be changing over time. This report is intended to evolve as the Commission's data, understanding, and methods to evaluate and address cumulative impacts evolve. Therefore, as Commissioners' understanding and evaluation of cumulative impacts evolves, the Director intends to accept requests for additional content for future iterations of this report. Requests will be included in future reports upon agreement by the full Commission and the Director, and are subject to data availability. These requests can happen at any point during the year. Requests made in a calendar year may require additional data, form changes, or time to review, which may affect the timing for inclusion.

As discussed elsewhere in the report, there continues to be data elements not included in this report because they were not available. The following topics will be included in future reports when the supporting data are sufficiently available. These include, but are not limited to:

- Actual water volumes used for drilling and completion activities compared to CIDER estimates,
- Actual emissions from oil and gas pre-production and production activities compared to CIDER estimates, and
- Emissions trends from well liquids unloading events.

As mentioned above, Subparagraph (7) allows the Commission to request additional information be included in this report, which were voiced at various Commission Meetings throughout the year. Many of the Commissioner suggestions were included in this report, while others were not currently possible with the data collected in CIDER or elsewhere in the OGDP process. Staff recognizes that since the implementation of changes to the Form 2A and the release of the Form 2B and Form 2C after the Mission Change Rulemaking, use of this form by both industry and staff would identify opportunities for form changes to increase clarity, improve data quality, etc. Some of the Commissioner questions may necessitate form changes prior to inclusion in future reports. For example, a request was made to understand differences in various metrics between operation type (e.g. natural gas wells, helium wells, etc.) and well type (vertical conventional, horizontal unconventional, etc.). This information is currently not included until operators submit a Form 2 (Application for Permit to Drill), which occurs after the OGDP is approved, meaning the form may not have been submitted for OGDPs approved during the year by the time this Report on the Evaluation of Cumulative Impacts is published. Other items that have been identified based on Commissioner discussions or are otherwise discussed in this Report on the Evaluation of Cumulative Impacts include, but are not limited to:

- Emissions benefit from PA activities,
- Produced water disposition, and
- Individual HPH post-interim reclamation disturbances.

Staff continues to compile and evaluate the scope of potential revisions and assess the steps to implement these requested revisions, which work drives the timing for integrating the necessary changes to the forms. Revisions to a form made mid-year may not be included in the report for that year as the data set would be incomplete. Changes to these forms that collect additional CIDER data are expected to enhance the analysis contained in this report in future years.

Appendix A - Air Quality Source Descriptions

To support the review of emissions as reported in CIDER, the following is a brief and simplified explanation of the emission categories. These categories were implemented to align with those used in ONGAEIR. More information on APCD accepted calculation methodologies can be found in the various resources on the ONGAEIR webpage.

Pre-Production Emissions

Process Heaters or Boilers are heaters or boilers that utilize natural gas as fuel. Common sources include but are not limited to: separator heaters, tank heaters, circulation (“inline” heaters),etc.

Storage Tanks are tanks that contain hydrocarbon liquid (condensate or oil) or produced water that can be permanent or temporary. Common sources include but are not limited to: condensate tanks, produced water tanks, flowback tanks, etc.

Venting or Blowdowns consist of natural gas that is vented or flared during drilling or completion operations that do not fit into another category. These activities are performed for safety or maintenance purposes. Common sources include but are not limited to: drill rig flaring, equipment blowdowns, venting of equipment to take a sample, etc.

Combustion Control Devices are devices used to control emissions, which may also be referred to as emission control devices or flares. At a minimum, this includes emissions from burning the pilot fuel of combustion control devices. Typically, where a control device is used to control the emissions of another category, the emissions are included in that category and not this one. This is a catch-all category for controlled emissions not reported under another category.

Non-Road Internal Combustion Engines are engines that are portable and not self propelled. Emissions from vehicles are not included in this category. While these non-road engines are typically exempt from APCD permit requirements, they are subject to federal requirements for non-road engines. Common sources include but are not limited to: drill rig generators, compression engines, hydraulic fracturing pump engines (i.e., “industrial engines”),etc.

Drill Mud consists of emissions from entrained gas from mud that is displaced while drilling the wellbore and the emissions from processing oil or synthetic based drilling muds in surface equipment. Emissions calculated from the mud that is displaced depend on the type of drill mud used: water based, brine, synthetic, or oil based mud.

Flowback or Completions is the gas stream from a flowback separator that is vented or flared. This does not include the flash emissions that occur when liquids are sent to tanks; such flash emissions are included in the Storage Tanks category.

Loadout is the emissions released when trucks are filled to carry hydrocarbons or produced water off of locations. Loadout emissions do not occur for the portions of hydrocarbon or produced water that are piped from location.

Production Emissions

Stationary Engines or Turbines are engines that are stationary sources, meaning they are not portable and not self propelled. Common sources include but are not limited to: wellhead compressors, generators, vapor recovery engines, instrument air compression, etc.

Process Heaters or Boilers are heaters or boilers that utilize natural gas as fuel. Common equipment includes but is not limited to: separator heaters, tank heaters, dehydration unit reboilers, etc.

Storage Tanks are tanks that contain hydrocarbon liquid (condensate or oil) or produced water that can be permanent or temporary. Common sources include but are not limited to: condensate tanks, produced water tanks, maintenance tanks, etc.

Dehydration Units are units used to remove hydrates from natural gas streams, typical units utilize glycol. Desiccant dehydration unit emissions occur when the unit is blown down for maintenance and is included in the Venting or Blowdowns category.

Pneumatic Pumps are pumps that utilize pressurized natural gas to operate a pump. Solar pumps and pneumatic pumps that utilize instrument air do not have emissions.

Pneumatic Controllers are controllers that utilize pressurized natural gas to operate. Pneumatic controllers that do not utilize hydrocarbon gas, for example those that utilize instrument air, do not have emissions and are called no-bleed pneumatic controllers. Pneumatic controllers are categorized as low-bleed controllers, high-bleed controllers, and intermittent bleed controllers.

Separator emissions consist of venting or flaring of the natural gas stream from a separator, regardless of the type of separator, which includes but is not limited to, high-low-pressure (HLP) separator gas, vapor recovery towers (VRT), etc. Some separator emissions are called associated gas venting.

Fugitive emissions are emissions from small components throughout the facility (e.g. connectors, valves, flanges, etc.). These emissions are surveyed by Lead Detection and Repair (LDAR) programs.

Venting or Blowdowns consist of natural gas that is vented or flared during drilling or completion operations that do not fit into another category. These activities are performed for safety or maintenance purposes. Common sources include but are not limited to: abnormal venting events, associated gas venting, compressor leaks, pit/pond emissions[22], some but not all routine or predictable (ROPE) emissions, etc.

Combustion Control Devices are devices used to control emissions, which may also be referred to as emission control devices or flares. At a minimum, this includes emissions from burning the pilot fuel of combustion control devices. Typically, where a control device is used to control the emissions of another category, the emissions are included in that category and not this one. This is a catch-all category for controlled emissions not reported under another category.

[22] Pit/Pond emissions were included in the Fugitives section for 2020 and 2021 calendar year reports to ONGAEIR.

Loadout is the emissions released when trucks are filled to carry hydrocarbons or produced water off of locations. Loadout emissions do not occur for the portions of hydrocarbon or produced water that are piped from location.

Non-Road Internal Combustion Engines are engines that are portable and not self propelled. Emissions from vehicles are not included in this category. Common sources include but are not limited to: workover engines, temporary generators, etc.

Well Bradenhead is the emissions vented through the well bradenhead.

Well Maintenance includes emissions from downhole well maintenance, well workovers, well liquids unloading events, well swabbing events, and well plugging activities.

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